US Army Corps of Engineers
Walla Walla District

Lower Snake River Juvenile Fish Mitigation Feasibility Study

Technical Report on Hydropower Costs and Benefits

FINAL

31 March 1999

Drawdown Regional Economic Workgroup:
Hydropower Impact Team

Co-Chairs:
US Army Corps of Engineers, Northwestern Division
(CENWD-NP-ET-WP)

Bonneville Power Administration (PGF)

FOREWORD

This document is the product of the US Army Corps of Engineers' (Corps) efforts to involve the region in the development of the *Lower Snake River Juvenile Salmon Migration Feasibility Report/Environmental Impact Statement (FR/EIS).* The Corps has reached out to regional stakeholders (states, tribes, Federal agencies, organizations, and individuals) for the input and development of various work products. This and various other products associated with the development of the EIS were authored and developed by these regional stakeholders and contractors. Although the Corps has acquired this document as part of its EIS process, the opinions and/or findings expressed herein do not necessarily reflect the official policy or position of the Corps. The Corps will review and incorporate information from these products into the analysis and development of the Draft FR/EIS.

In addition, this analysis is only one part of the overall Economic Appendix of the EIS. Other critical components of the economic analysis include power, water supply, recreation, regional, social, and tribal impacts. For a true economic analysis of the implications of any of the study alternatives, economic costs and benefits of all the components of the analysis must be considered, but without any individual component taken out of context.

This document is being released for **information purposes only**. The Corps will not be responding to comments at this time. The formal comment period will coincide with the release of the Draft FR/EIS, expected in Fall 1999.

DRAWDOWN REGIONAL ECONOMIC WORKGROUP: HYDROPOWER IMPACT TEAM

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EXECUTIVE SUMMARY

STUDY APPROACH

This technical report concentrated on the identification of the net economic effects associated with changes in hydropower production from the Lower Snake River Dams. To identify the economic effects different approaches were taken and a range of study assumptions were evaluated. The basic study approach was to establish an oversight team of interested individuals (the Hydropower Impact Team) to review and guide the analyses being conducted primarily by the staffs of the Bonneville Power Administration (BPA) and the Corps of Engineers (Corps).

Two separate, but similar, system hydro-regulation models were used by the Corps and BPA to estimate the amount of hydropower generation that would occur in the Columbia River basin with the different alternatives of this study. These models simulated 50 and 60 historic water years and provided estimates of monthly hydropower generation in the Pacific Northwest (PNW) in each of the water years. Three system power models were used to identify the net economic costs associated with the change in hydropower generation. The three power models are all proprietary models that have been used by the Corps, BPA, and the Northwest Power Planning Council (NPPC) in other studies. The three models were similar but varied in scope. All the models identified which power resources would be operated to meet expected loads in the future. The BPA and Corps models identified the variable costs (production costs) associated with meeting load in the PNW and California, and the total Western United States, respectively. The BPA model also determined the fixed costs by defining what new power resources should be built to replace lost hydropower capacity. The NPPC model identified the market-clearing prices at the wholesale level for each time period. The results from the BPA and NPPC models served as the primary estimate of net economic effects, and the Corps model was used primarily to confirm results from the other models and test numerous study assumptions. The net economic effects computed from the three models were surprisingly close.

DESCRIPTION OF EFFECTS

The net economic costs associated with each alternative were based on a comparison to the assumed base condition defined by alternative A1. The net economic costs consisted of three components: (1) Annual net economic effects determined by system production costs or market-clearing prices, (2) Ancillary Services, and (3) Transmission Reliability Costs.

The annual net economic effects were estimated by defining the total system production costs (system variable costs + fixed costs of new capacity) for the PNW and Pacific Southwest (PSW), and by the market-clearing price multiplied by the change in hydropower generation. One major question in this analysis was how many new generating resources would be constructed to replace the lost capacity associated with breaching the Lower Snake River dams. The amount of this replacement capacity influences the generation reliability in the PNW and constitutes a major element of the net economic costs. The BPA and NPPC models estimated how much new capacity would be built based on economic optimization routines which selected the level of new capacity that minimized the total system production costs. The report examined different levels of new capacity and it was found that the total system production costs did not vary significantly with different levels of new capacity. This occurred because the variable production costs tended to reduce with construction of more new capacity consisting of combined cycle combustion turbine, gas-driven power plants. The reduction in variable costs somewhat offset the increase in fixed costs with the addition of new capacity.

The ancillary services are the benefits provided by hydropower facilities that are not reflected in the energy and capacity values discussed above. Hydropower traditionally has been acknowledged to have an advantage over most thermal units because of its ability to start quickly, follow load, to act as a capacitor or inductor to improve system power factors, and in other ways contribute flexibility to power systems. The value of these ancillary services was based on the revenue that BPA receives for providing these services from the Lower Snake River plants.

The PNW electricity transmission grid was originally constructed in combination with the generation system. Since the transmission and generation systems interact electrically, the loss of hydropower generation will affect the transmission system's ability to move bulk power and serve regional loads. Hence, the removal of the Lower Snake River dams will impact the reliability of the transmission system, and the costs associated with maintaining the transmission reliability at the current level is estimated in this report.

Other economic effects that were not quantified in this technical report were the probable changes in air and water quality that will occur with different levels of hydropower production. Separate Air Quality and Water Quality Appendices are included in the Feasibility Report, and interested readers are referred to those appendices.

RESULTS BY ALTERNATIVE

A range of different water conditions and different economic forecast conditions were examined in the study and the effect of the uncertainty associated with these different elements is document in the report. Table ES-1 shows the range of net economic effects that were estimated based on the different power system models and different assumptions of future economic conditions. These effects represent the net economic costs compared to the base condition of alternative A1. A positive number means that with the respective alternative the economy will have additional costs, or stated differently, a loss in hydropower benefits associated with the four Lower Snake River Dams.

Three future economic forecast conditions were examined based on a combination of low, medium and high forecasts of fuel prices, demand for electricity (loads), and efficiency of future generating resources. Table ES-1 shows the range of net economic effects based on the 6.875% discount rate and the hydropower generation based on the average of all simulated water years. The report presents this same type of information for discount rates of 4.75% and 0.0%, and the range of effects with different water years. The difference between minimum and maximum values in each section of Table ES-1 represents the range of results with the different economic models and high and low estimates for transmission related costs.

Table ES-1
Total Average Annual Net Economic Effects
Differences From Alternative A1
6-7/8% Discount Rate, 1998 $ Million, Average of All Water Conditions

Medium Economic Conditions

Alternatives	System Costs		Transmission Reliability Costs		Ancillary Services Cost	Total Effects	
	Minimum	Maximum	Minimum	Maximum		Minimum	Maximum
A2	($10)	($7)	$0	$0	$0	($10)	($7)
A3	$221	$255	$22	$28	$8	$251	$291
A5	$204	$251	$22	$28	$8	$234	$287
A6a	($21)	($17)	$0	$0	$0	($21)	($17)
A6b	($3)	($0)	$0	$0	$0	($3)	($0)

Low Economic Conditions

Alternatives	Range of Costs		Transmission Reliability Costs		Ancillary Services Cost	Total Effects	
	Minimum	Maximum	Minimum	Maximum		Minimum	Maximum
A2	($7)	($5)	$0	$0	$0	($7)	($5)
A3	$151	$187	$22	$28	$8	$181	$223
A5	$140	$184	$22	$28	$8	$170	$220
A6a	($19)	($10)	$0	$0	$0	($19)	($10)
A6b	($2)	$0	$0	$0	$0	($2)	$0

High Economic Conditions							
Alternatives	Range of Costs		Transmission Reliability Costs		Ancillary Services Cost	Total Effects	
	Minimum	Maximum	Minimum	Maximum		Minimum	Maximum
A2	($16)	($12)	$0	$0	$0	($16)	($12)
A3	$329	$353	$22	$28	$8	$359	$389
A5	$307	$338	$22	$28	$8	$337	$374
A6a	($31)	($27)	$0	$0	$0	($31)	($27)
A6b	($5)	$1	$0	$0	$0	($5)	$1

POINT ESTIMATE OF EFFECTS

To integrate the wide range of effects into results from other elements of the Lower Snake River Juvenile Mitigation Feasibility Study, point estimates were needed. The following presents a point estimate of these results based on the average between the range of results for the medium forecast of the economic parameters, and the average of all the water years. The study team considers these point estimates to be reasonable estimates to compare to point estimates from other elements of the Feasibility Study. However, the full range of uncertainty in the economic results, presented in section 6.0, should be considered by the decision-makers. Each alternative was analyzed based on a base year in 2005. The annual costs were based on a 100 year period of analysis at three discount rates of 6.875%, 4.75%, and 0%. The three discount rates had little impact on the net average annual costs of each alternative. So, the following point estimates are based on the 6.875% discount rate.

Alternative A2, System Improvements and No Drawdown of Lower Snake River Dams. Several different combinations of project improvements were considered under this alternative. This hydropower analysis did not consider the minor differences in generation that might occur at the projects with the different project measures. This alternative will result in increases in system hydropower generation. It is not expected that the transmission system would be impacted with this alternative, and the changes in ancillary services are considered to be minimal. The point estimate of average annual net economic costs was $- 9 million. The negative net costs represent a benefit over the base condition.

Alternative A3, Breaching the Four Lower Snake River Dams. With this alternative the four projects would be operated at the natural river levels and no hydropower generation would occur at these sites. The analysis of this alternative did not include any hydropower impacts that may occur with changes in irrigation withdrawal from the Lower Snake River reservoirs. The point estimate of average annual net economic costs consists of three components: (1) the point estimate of system costs is $ 238 million, (2) the point estimate of transmission reliability costs is $25 million, and (3) the ancillary service costs are $ 8 million. Hence, the annual total net economic costs are $271 million.

Alternative A5, Breaching the Four Lower Snake River Dams and No Snake River Flow Augmentation. This alternative is similar to A3 except some additional system hydropower generation and the timing of the generation will change. The analysis of this alternative did not include any hydropower impacts that may occur with changes in irrigation from the Lower Snake River reservoirs. The point estimate of system costs is $228 million. The point estimate of transmission reliability costs is $25 million, and the ancillary service costs are $ 8 million. Hence, the annual total net economic costs are $261 million.

Alternative A6a, System Improvements and Additional Flow Augmentation from the Upper Snake Basin of 1 Million Acre-Feet. The examination of hydropower impacts of this alternative in this report did not include the changes in hydropower generation that will occur upstream of Brownlee Dam. The U.S. Bureau of Reclamation report, entitled *Snake River Flow Augmentation Analysis* provides the hydropower impacts with this alternative in the Upper Snake River Basin. The hydropower generation in the Lower Snake River and Columbia Basins is larger than with the base case. It is not expected that the transmission system would be impacted with this alternative, and the changes in ancillary services are considered to be minimal. The point estimate of average annual net economic costs was $ -19 million (benefits over the base condition). The results of the Bureau of Reclamation’s study should be added to this amount to obtain all the hydropower costs associated with this alternative.

Alternative A6b, System Improvements and a Reduction in Flow Augmentation from the Upper Snake Basin of 0.427 Million Acre-Feet. The examination of hydropower impacts of this alternative in this report did not include the changes in hydropower generation that will occur upstream of Brownlee Dam. The U.S. Bureau of Reclamation report, entitled *Snake River Flow Augmentation Analysis* will provide the hydropower impacts with this alternative in the Upper Snake River Basin. The hydropower generation in the Lower Snake River and Columbia Basins is slightly larger than with the base case. It is not expected that the transmission system would be impacted with this alternative, and the changes in ancillary services are considered to be minimal. The point estimate of average annual net economic costs was $- 1 million (benefits over the base condition). The results of the Bureau of Reclamation’s study should be added to this amount to obtain all the hydropower costs associated with this alternative.

Alternatives B1, B2, C1, and C2, Drawdown or Breaching of John Day Dam and the Breaching of the Four Lower Snake River Dams. This report did a partial analysis of the John Day Dam drawdown alternatives. The examination of the hydropower system costs associated with the John Day alternatives was initiated in this study to utilize the study team that was assembled for the Feasibility Study. Only the annual net system costs with these alternatives were estimated in this study. The annual system costs were estimated at $469, $405, $357, and $294 million, for alternatives B1, B2, C1, and C2, respectively. These costs represent only part of the net economic costs because no estimate of the ancillary services and transmission reliability costs were estimated in this report. Since initiation of this Feasibility Study, the Portland District of the Corps of Engineers has begun the *John Day Drawdown, Phase I Study*. The Phase I study will examine all the hydropower costs associated with drawdown of the John Day Dam.

1. INTRODUCTION

1.1 PURPOSE AND SCOPE

The purpose of this Technical Report on Hydropower Costs and Benefits is to document the net economic costs associated with changes in hydropower production at the four Lower Snake River dams. This report presents in detail the process and results of hydropower studies. This document serves as the background documentation for the findings presented in the Economic and Social Appendix of the Lower Snake River Juvenile Mitigation Feasibility Study (hereafter referred to as the Feasibility Study).

The Columbia River Basin hydropower projects serve as a major element in the Pacific Northwest (PNW) electrical industry, and provide about 60 percent of the total regional electrical energy needs and 70 percent of the total electrical generating capacity in the region on an average basis. Hydropower traditionally has been acknowledged by the electric power industry to have an advantage over most thermal units because of its high reliability, fast loading and response capabilities, low exposure to price inflation, extremely long life, and spinning reserve capabilities. This study has attempted to identify and value all of these benefits.

The nature of hydropower is that it is available in different amounts from year to year depending on streamflow conditions. This variability between years, months, weeks, and even hours is an important factor in establishing the economic value of the hydropower. The storage of water in reservoirs allows for manipulation of this variability by storing water during high flow periods and releasing it at a later period for hydropower production, and other beneficial uses. In wet years, the amount of hydropower generation can be significantly greater than the average conditions, and this energy (commonly referred to as secondary) can serve as a major part of the export market outside of the PNW. In low water years, or high demand periods within a year, energy is often imported into the PNW to meet the power demands. Because of these historical relationships the Western Systems Coordinating Council (WSCC) is an interconnected power system. Consequently, any changes in the generation of PNW hydropower could impact the amount of energy bought and sold, and the amount of new generating facilities to be built, throughout the entire West Coast of the United States. For these reasons, the scope of this analysis is the entire western United States and parts of Canada as defined by the WSCC.

The WSCC is a one of nine regional energy reliability councils that were formed due to a national concern regarding the reliability of interconnected bulk power systems. The WSCC comprises all or part of the 14 Western States and British Columbia, Canada, over 1.8 million square miles.

The WSCC is partitioned into four major areas, which reflect the varying and sometimes extreme geographic and climatic conditions. Transmission lines span long distances from the PNW, with abundant hydroelectric resources, to the Southwest, with large coal-fired and nuclear resources. Figure 1 shows the geographic scope of the WSCC. The WSCC sub-areas are:

I. Northwest Power Pool Area (NWPP)

II. Rocky Mountain Power Area (RMPA)

III. Arizona-New Mexico Power Area (AZ/NM)

IV. California-Southern Nevada Power Area (CA/SNV)

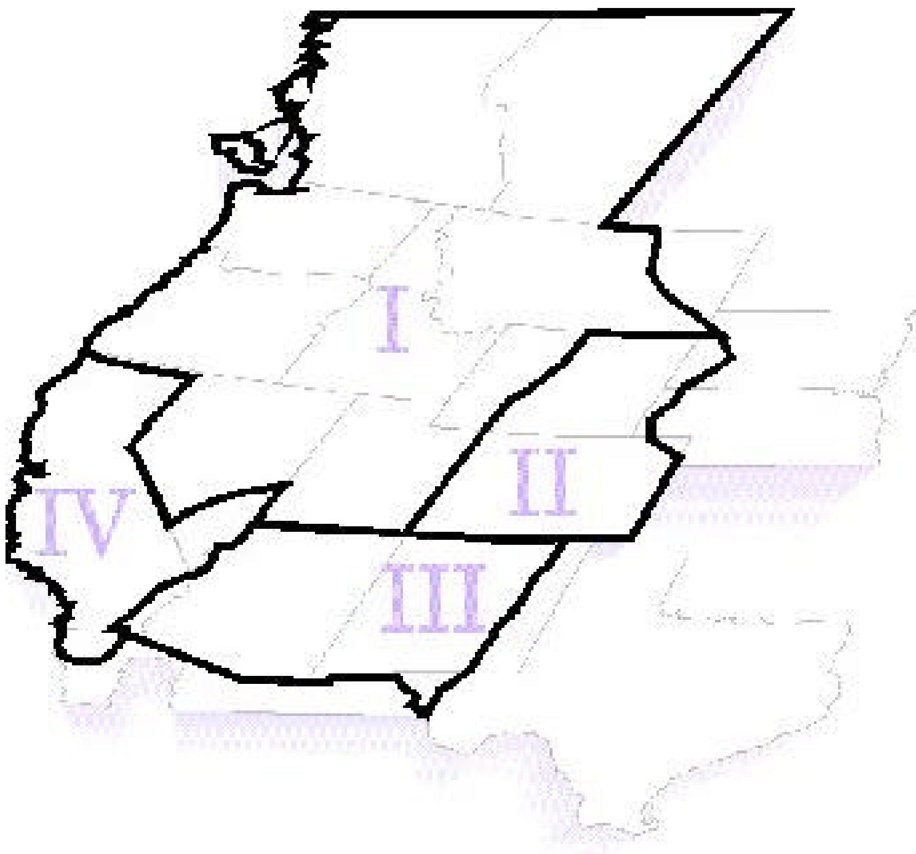


Figure 1: Western Systems Coordinating Council (WSCC)

1.2 PARTICIPANTS

The analysis was conducted jointly by the Corps of Engineers utilizing the Power Branch of the Northwestern Division (CENWD-NP-ET-WP), and the regional power marketing agency, Bonneville Power Administration (BPA), Power Business Line, Federal Hydropower Projects office. CENWD-NP-ET-WP is designated as the Corps of Engineer's Mandatory Center of

Expertise for Hydropower System-Economic Evaluation, and the Corps regulation ER 1110-1-8158 requires the use of this office for power system analysis involving Corps projects. It was recognized from the start of the study that each of these two agencies have different evaluation needs, so where appropriate, the impacts are presented to meet each agency's (and other area interests') specific needs.

As with other economic impact areas, an oversight group was formed to assist in the analysis and to provide a forum for interested parties to provide input. The Hydropower Impact Team (HIT) consisted of 10 to 20 members from numerous interested entities such as the Northwest Power Planning Council, the Bureau of Reclamation, National Marine Fisheries Service, regional tribes, river interest groups, and environmental groups. The HIT met regularly during the study to discuss appropriate approaches and assumptions to use in the analysis. The HIT also provided review and comments on drafts of this hydropower report.

1.3 STUDY PROCESS

The study process incorporated several elements to arrive at the estimate of economic effects associated with changes in hydropower with each of the alternatives. The process first considered how the impacted hydropower projects currently function, and used system hydro-regulation studies to estimate how much hydropower generation will occur with the different alternatives and different water conditions. This information was then incorporated into power system models to estimate how changes in hydropower generation will affect generation from other more costly power resources. The impacts of these changes on the market prices over time were also estimated. A wide range of key study assumptions was investigated and the uncertainties associated with these assumptions were examined. Sensitivity tests were performed on some of the major study assumptions to assure that results were reasonable from a wide range of viewpoints. The financial impact on regional ratepayers and possible mitigation for these impacts were also investigated. The power system modeling tools were used to help identify the changes in air pollutant emissions with the different alternatives.

The Drawdown Regional Economic Workgroup (DREW) established the basic analysis criteria to use in all economic studies for the Feasibility Study. The key economic criteria established for this study were that the period of analysis was 100 years, and the base year is 2005. Costs and benefits are presented in real terms, based on the 1998 price level. Three different discount rates were used to meet the needs of the different study participants; 6.875 %, 4.75 %, and zero. Comparison of alternatives were done primarily on an average annual basis, in which net present-worth values were annualized over the 100 year period of analysis.

2.0 HYDROPOWER CHARACTERISTICS OF EXISTING SYSTEM

2.1 BASIN HYDROLOGIC CONDITION

The Snake River, which is 1,038 miles long, begins in northwestern Wyoming. It flows west and north, forming part of the borders between Oregon and Idaho and between Idaho and Washington. The Snake River is a major tributary of the Columbia River with its confluence in south central Washington near the cities of Pasco and Kennewick.

The Columbia and Snake Rivers today are considerably different from when the region was first settled. Since the 1930s, some 255 Federal and non-Federal dams have been constructed in the basin. The Federal agencies have built 30 major multi-purpose projects on the Columbia and its tributaries.

The hydropower projects fall into two major categories: storage and run-of-river. The main purpose of the storage reservoirs is to adjust the river's natural flow patterns to conform more closely to water uses. The storage projects store the spring runoff water. In the late summer, fall and winter when stream flows would ordinarily be low, water is gradually released from storage reservoirs for many river uses, including power.

Run-of-river projects have limited storage and were developed primarily for navigation and hydropower generation. These projects pass water at the dam at nearly the same rate it enters the reservoir. Reservoir levels behind these projects vary only a few feet in normal operations. The four Lower Snake River dams are run-of-river projects.

2.2 PROJECT CHARACTERISTICS

The hydropower projects of most interest to this study are the four Lower Snake River projects of Ice Harbor, Lower Monumental, Little Goose, and Lower Granite, and the Lower Columbia River project of John Day. However, almost all the hydropower projects in the Columbia-Snake system will be impacted under at least one of the alternatives being investigated. Table 1 describes some of the hydropower characteristics of the four Lower Snake and John Day hydropower projects. Three of the Snake River projects are essentially identical in terms of hydropower facilities. The Ice Harbor project was

constructed several years before the others and has less capacity. The overload capacity represents the maximum (overload) output that can be achieved. The average annual energy is presented in two different units: the average MW (aMW) which is the amount of generation averaged over all the hours of the year, and the annual MWh which is the sum of all generation over the entire year. This energy data was taken from the average of 60 historic water years for the base condition. The plant factor figures were computed by dividing aMW amounts by the maximum capacity. The John Day hydropower capacity is nearly 1,000 MW less than the four Snake River projects, but the average annual energy is almost the same. This is because the John Day project is located on the Lower Columbia River and has considerably more water passing through the project.

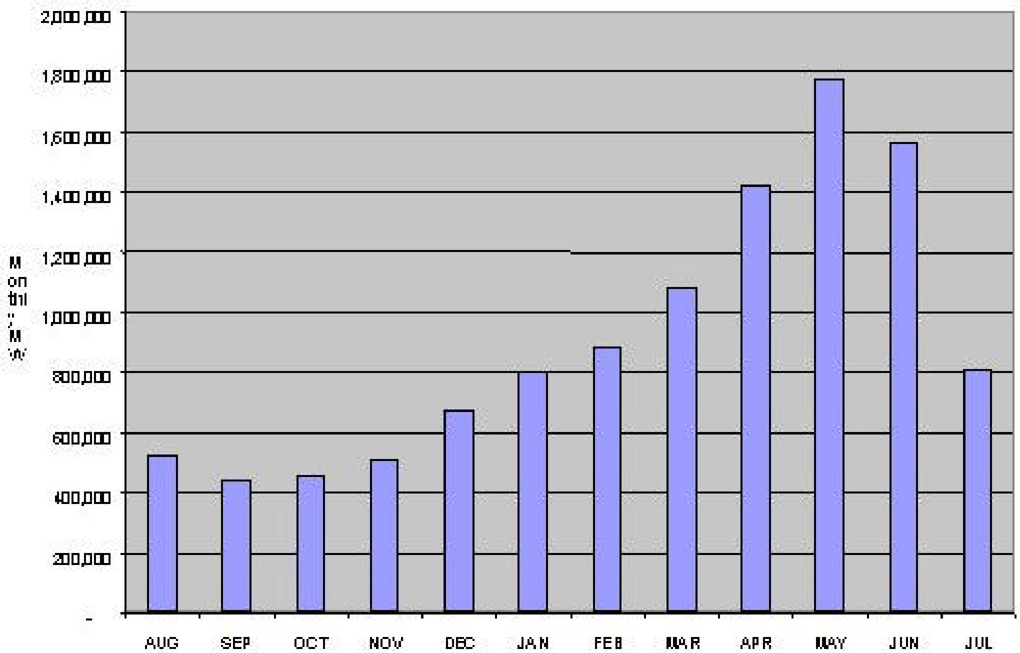
Table 1
Hydropower Plant Characteristics

	Ice Harbor	Lower Monumental	Little Goose	Lower Granite	Lower Snake Total	John Day
Number Units	6	6	6	6	24	16
Capacity Per Unit (MW)	3 (90) 3 (111)	6 (135)	6 (135)	6 (135)		16 (135)
Total Nameplate Capacity (MW)	603	810	810	810	3,033	2,160
Overload Capacity (MW)	693	931	931	931	3,486	2,484
In-Service Date	1 (1961) 2 (1962) 3 (1975)	2 (1969) 1 (1970) 3 (1979)	3 (1970) 3 (1978)	3 (1975) 3 (1978)		16 (from 1968 to 1971)
Average Annual Energy (aMW) Base Condition[1]	264	332	317	333	1,246	1,170
Average Annual Energy (1,000 MWh) Base Condition[1]	2,313	2,908	2,777	2,917	10,915	10,249
Plant Factor Base Condition	38%	36%	34%	36%	36%	47%

[1]Model results were provided to be consistent with other data in this report. Actual historic generation over the period from 1976 to 1997 was within 3 percent (+/-) of the model results for the individual projects.

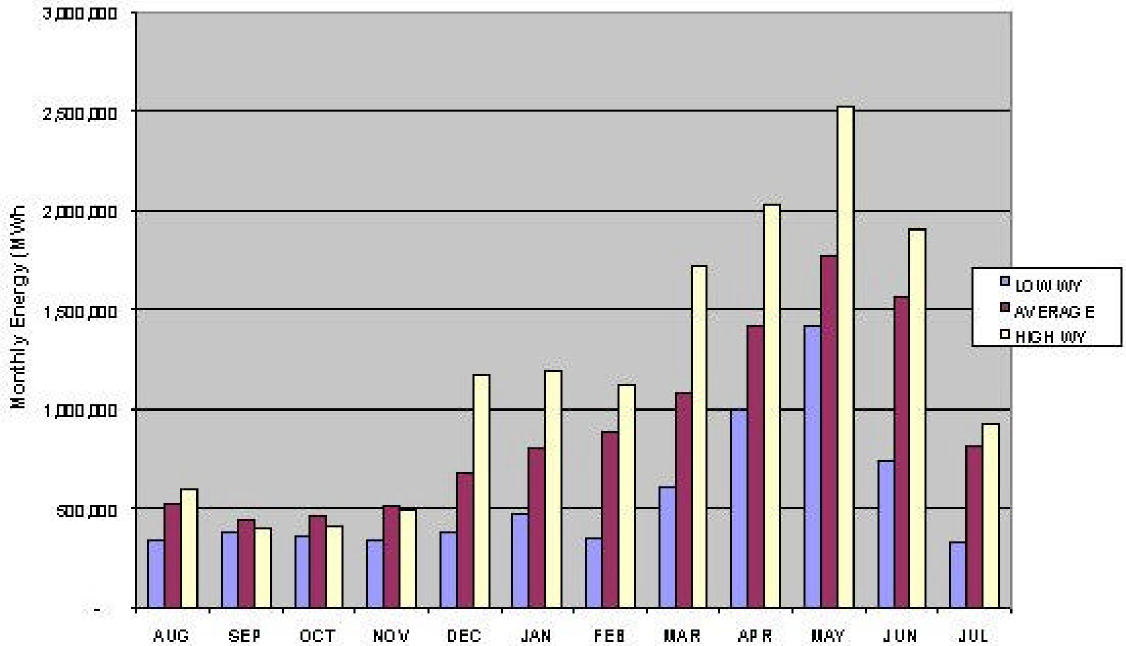
Figure 2 shows an estimate of the average monthly generation of the four Lower Snake River plants by month based on a system hydro-regulation model for the base condition (Alternative A1). This is the alternative from which all other alternatives are evaluated, and best represents the current operation of these plants. The monthly generation is the average of 60 different estimates for that month based on actual runoff for each of the 60 water years from year 1929 to 1988. The monthly generation amounts reflect both the run-of-river nature of these projects, and the storage capability of the upstream storage reservoirs. The upstream storage does store some of the high spring runoff, but this storage is relatively small compared to the entire annual runoff amounts. Consequently, the generation in the spring freshet period far exceeds the generation in the rest of the year.

FIGURE 2 Lower Snake River Average Generation
HYSSR Results - Alternative A1
Monthly Average for 60 Year Simulations



The amount of generation from these plants can change significantly in different water years. For example, Figure 3 compares the monthly generation for a 60-year average simulation, a low water year (1930-31), and a high water year (1955-56). On a seasonal basis the variations from low water years to high water years can be even more pronounced. For example, in the summer months the average monthly generation of the lowest month is about 75 percent lower than the average summer monthly generation over the 60 water years of record. The highest summer monthly generation is about 160 percent larger than the monthly average. This range of variation is similar for the winter months, but the year-by-year variance is considerably less in the fall and spring months.

FIGURE 3 A1 Results - Monthly Generation - 4 Snake Riv Dams
Low WY (1930), High WY (1955-56) & 60 Year Average



The capacity of the Lower Snake River projects is reflected in Figure 4. This figure represents the maximum generation these plants can provide in each month (or part month), under current operation. These plants do not operate at these maximum outputs during the winter because there is insufficient water to do so for very long periods of time, and limited storage in each reservoir. For example, during a recent five day cold snap in the PNW in December 1998, the maximum combined output from the four projects was approximately 1,800 MW for two hours. The daily peak generation during this peak demand period was around 1,600 MW. The lower maximum capacity shown in figure 4 in the April through October period reflects operational criteria that were established in the 1995 Biological Opinion (95 BiOp) to increase survival of salmon and steelhead during this fish migration period. The Lower Snake River projects were designed to operate within a 3 to 5 foot pool elevation range. Since the 95 BiOp the pools are operated near the minimum operating pool during the fish migration period and this reduces power generating head and hence capacity. Also, during this period the operation of the power turbines is restricted to within one percent (+/-) of the peak efficiency level that minimizes the impacts to juveniles passing through the turbines. This serves to further restrict the maximum output of each unit by restricting the ability to operate the units at the maximum output.

FIGURE 4 Plant Capability (MW)
Lower Snake Projects (Combined)

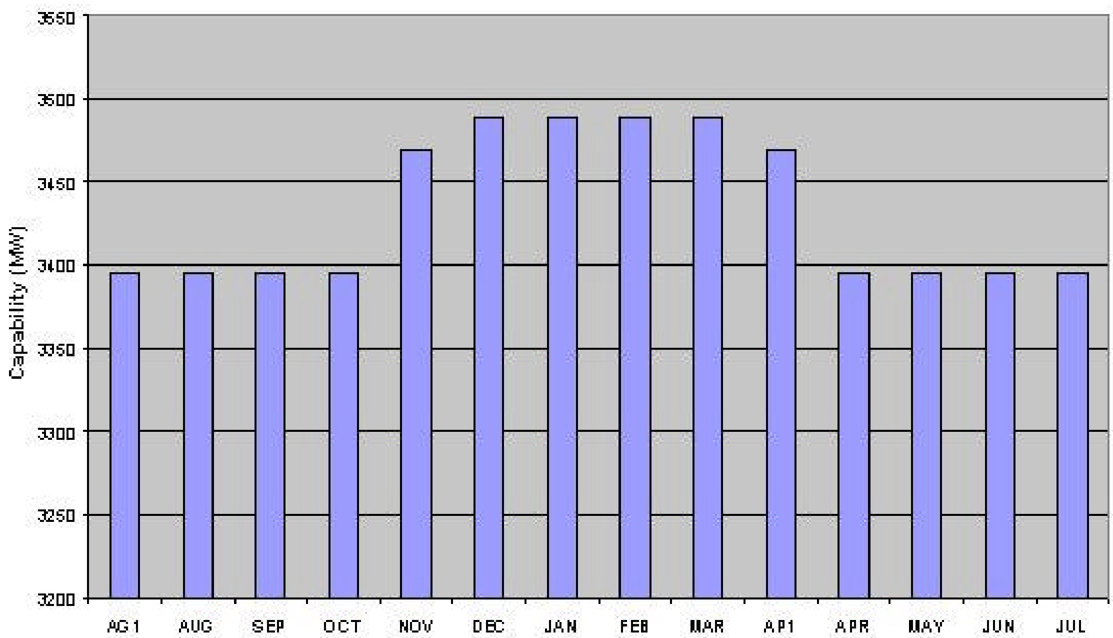


Figure 5 presents the monthly generation-duration curve based on the 60 water year conditions from 1928 to 1988, for the base condition. The generation in this figure is the combined monthly generation of the four Lower Snake River projects. This figure shows the percent of time in which monthly generation equals or exceeds the generation in MW. For example, the monthly generation equals or exceeds 1,000 MW about 50 percent of the months of the 60 water years, and equals or exceeds 2000 MW about 20 percent of the time. It is important to note which months the high average generation occurs. The months in which 2,000, 2,500, and 3,000 average MW is equaled or exceeded are summarized in Table 2. This table shows that these high average generation amounts never occur in the months of August through December, and only occasionally in the months of January, February, and March. However, during the winter months the projects are often operated at these high output levels but not for the entire month. That is, during the winter months the projects do follow peak demand but the amount of water available is often too low to produce high monthly average generation.

FIGURE 5 Lower Snake River Plants - Monthly Generation Duration

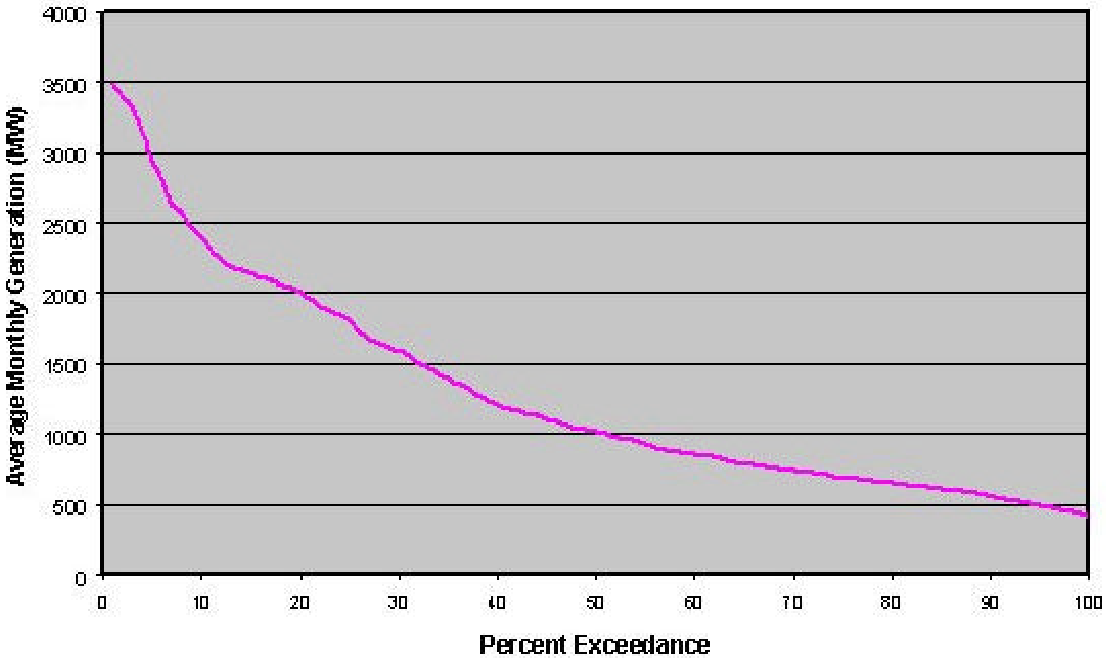


Table 2
Summary of Lower Snake River Monthly Generation
Base Condition, 60 Water Years

	Aug thru Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Monthly Average Generation Equal or Exceed 2,000 aMW								
Count out of 60 years	0	3	7	12	32	49	33	1
% of Years >= 2000	0%	5%	12%	20%	53%	82%	55%	2%
Monthly Average Generation Equal or Exceed 2,500 aMW								
Count out of 60 years	0	0	3	5	10	18	17	0
% of yrs >= 2500	0%	0%	5%	8%	17%	30%	28%	0%
Monthly Average Generation Equal or Exceed 3,000 aMW								
Count out of 60 years	0	0	0	2	2	10	9	0
% of yrs >= 3000	0%	0%	0%	3%	3%	17%	15%	0%

The hourly operation of the Lower Snake River plants is described in the following figures. The hydropower generation at the plants is determined primarily by the amount of Snake River water arriving at Lower Granite because the four reservoirs have very limited storage capability and only minor tributary inflows into the reservoirs. These projects do not have the ability to store water over the week, month, or season. The projects can somewhat shape the amount of generation throughout the day with the limited storage within the top 3 to 5 feet of operating range over the juvenile fish non-migrating periods of November through March. Figure 6 shows the combination of hydropower generation at the four projects over a sample week in the month of February of 1994 and a week in February of 1995. Figure 7 shows the generation from the plants for sample weeks in May of years 1994 and 1995. As can be seen from these two figures the shape of the generation over each day of the week in the respective months is similar, but the magnitude of the generation is significantly different. The magnitude of generation reflects the water availability in the specific week. For example, the week of 6 February 1995 has an average generation of 513 aMW, which is relatively low at this time of year. During the week of 5 February 1994 the average generation was 784 aMW with a peak generation during the week of 1,448 MW. In contrast the week of 22 May 1995, which is during the spring freshet period, had an average generation in the week of 2,446 aMW and a peak generation of 2,710 MW. These weeks are provided as sample weeks during periods of high power demand (February) and high flow periods (May), and are not intended to reflect the extremes of peak load or peak generation.

FIGURE 6 Lower Snake Projects - Example February Weeks

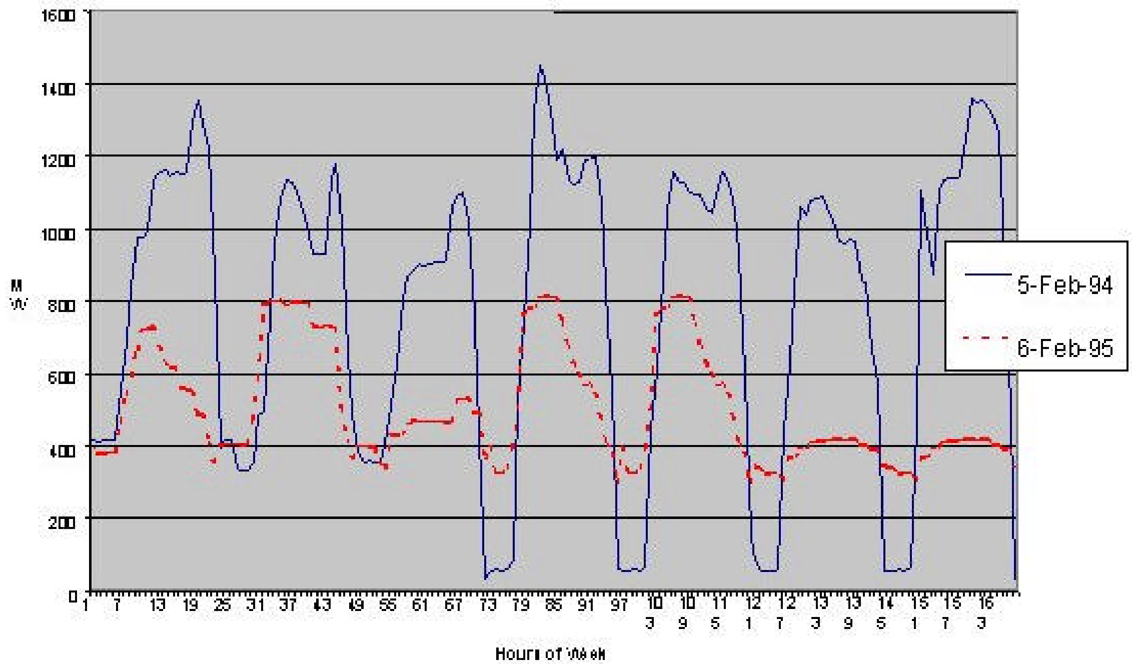
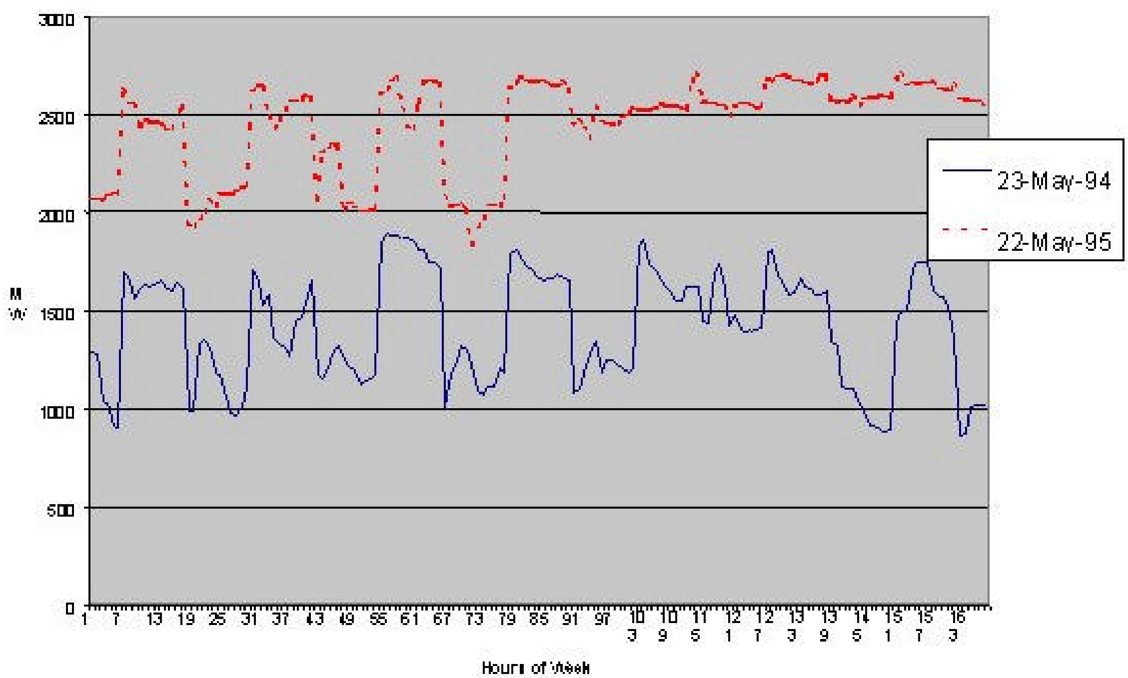
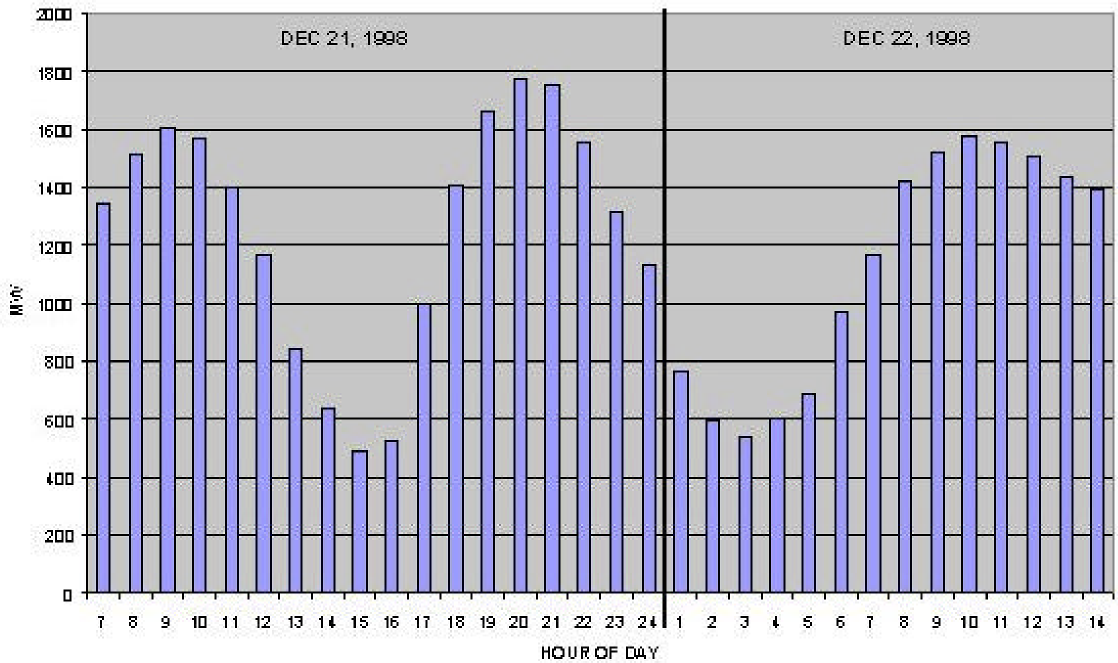


FIGURE 7 Lower Snake Projects - Example May Weeks



The Lower Snake projects have the ability to follow load on a daily basis. The generation throughout a day is shaped to meet the power demand to the extent possible given the amount of water that is available and the other operation constraints such as spill and flow requirements. Figure 8 demonstrates the hour by hour operation on two recent days of 21 and 22 December 1998 (Monday and Tuesday). The operation during the non-peak hours is very low to allow for much higher generation during the peak demand periods. The non-peak generation does not equal zero because some generation is needed to provide electricity to serve the needs of the powerhouse and the dam. The wide swings in total generation are much more common in the low flow periods of fall and winter. During the higher runoff periods the generation through the day does not vary as much.

FIGURE 8 Lower Snake River - Daily Example - 21 & 22 Dec 1998



The hydropower plants in the system provide other products on an hourly basis that are generally referred to as ancillary services. The quick start up ability of hydropower units provides spinning reserves to the system, which can be called on to generate electricity almost immediately upon request. This spinning reserve is needed to quickly respond to emergencies in the system such as power plant or transmission line failures. The generation from hydropower units can be adjusted up or down quickly to provide automatic generation control to preserve required frequencies in the transmission system. The units are also often operated as a motor, in a condensing mode, to balance the needs of the transmission system. BPA has traditionally provided these services from hydropower plants to their customers and the costs have been bundled into the basic electricity price. However, with the new competitive nature of the electricity market, BPA is now beginning to charge separately for these services. The ancillary services provided by the four Lower Snake River Dams are discussed further in section 5.6.

2.3 POWER SYSTEM CHARACTERISTICS

Table 3 demonstrates to what extent each power-generating source is used in the PNW. As can be seen in the table, hydropower makes up about 67 percent of the Pacific Northwest's total generating capacity, followed by coal. Next in terms of capacity available to meet demand is electricity imported over the intertie system from regions outside of the PNW. The firm energy amount shown in this table reflects that which can be generated in the low water year of 1936-37.

The year 1937 has been defined as the critical year for defining firm energy in many regional power planning studies. A distinction is often made between firm (also referred to as primary) energy and non-firm (referred to as secondary) energy in power markets because the firm energy can be counted on even in the most extreme historical low water years. More description of the power market and relative values is provided in section 5.3 below.

Table 3
The Pacific Northwest Electric Generating Resources 1997[1]

Resource Type	Sustained Peak Capacity (MW)[2]	Percent of Total Capacity	Firm Energy[2] (aMW)	Percent of Firm Energy
Hydro	25,887	67%	12,187	57%
Coal	4,521	12%	4,061	19%
Nuclear	1,162	3%	841	4%
Imports	2,996	8%	1,669	8%
Combustion Turbines	1,665	4%	753	4%
Non-Utility Generation	1,166	3%	1,051	5%
Cogeneration	775	2%	675	3%
Other	264	1%	171	1%
Total	**38,436**	**100%**	**21,408**	**100%**

[1]Source: BPA's *1997 Fast Facts*
[2]For more information, see BPA's *Pacific Northwest Loads & Resources Study*

Table 4 provides generation and capacity information for the entire WSCC, based on actual generation in 1997, rather than the firm energy. The most prominent source of generating capacity and energy in the WSCC is hydropower, but to a significantly less extent than in the PNW. Coal and natural gas driven thermal plants provide a much larger share of capacity and energy in the WSCC than in the PNW. However, hydropower makes up the vast majority of system capacity and generation in the PNW, and is the largest contributor for the entire WSCC.

Table 4
Western Systems Coordinating Council (WSCC)
Electric Generating Resources, 1997

Resource Type	Capacity (MW)	Percent of Total Capacity	1997 Energy (aMW)	Percent of Total Energy
Hydro-Conventional	61,043	39%	33,367	39%
Hydro-Pump Storage	4,316	3%	533	1%
Steam-Coal	36,325	23%	28,378	33%
Steam-Oil	746	<1%	239	<1%
Steam-Gas	23,241	15%	5,018	6%
Nuclear	9,258	6%	7,472	9%
Combustion Turbine	5,846	4%	206	<1%
Combined Cycle	3,777	2%	779	1%
Geothermal	3,060	2%	2,270	3%
Internal Combustion	293	<1%	--	<1%
Cogeneration	8,119	5%	5,954	7%
Other	1,891	1%	1,317	2%
Pump-Storage Pumping			(445)	-1%
Total	**157,915**	**100%**	**85,089**	**100%**

Source: 1998 WSCC Information Summary

3. SYSTEM HYDRO-REGULATION STUDIES

3.1 HYDRO-REGULATION MODELS

The first step in defining the power impacts was to utilize system hydro-regulation models. These models simulate the operation of hydropower plants with each alternative under historical water conditions encountered over 50 or 60 water years, depending on which model is used. Two models were used to define the power impacts at each hydropower plant in the Pacific Northwest with the alternative operations of the system. The model used by the Corps is the Hydro System Seasonal Regulation Program (HYSSR) and it simulates water years from 1929 to 1988. The BPA model is the Hydro Simulator Program (HYDROSIM, sometimes labeled HYDSIM) which simulates years 1929 to 1978. On a conceptual level, the models are almost identical.

But since the two agencies that designed and use them have distinct missions, each has a unique point of view. The major output of either model used in this analysis is a month-by-month hydropower generation amount from each hydropower plant in the Columbia Basin, for each of the years simulated by the models. See Appendix ____, Hydro-Regulation Appendix, of the Lower Snake River Juvenile Mitigation Feasibility Study for detailed description of the hydro-regulation models.

3.2 ALTERNATIVES

The alternatives that were evaluated in the hydropower analysis form a somewhat larger list than for other impact areas such as navigation and recreation. In particular, a sensitivity analysis was undertaken to examine the effects of drawing down the John Day Reservoir to the natural river level (approximately elevation 170 feet) and the spillway level (elevation 210 feet). This sensitivity was included because at the start of this study proposals were made to study the drawdown of the John Day project. In October 1998 the Portland District of the Corps of Engineers started the Phase 1 John Day Drawdown Study and the process developed here will be used in that study. The Hydropower Impact Team (HIT) recognized that evaluation of John Day drawdown alternatives was outside the scope of this Feasibility Report. But the team was concerned that the identification of the hydropower economic costs for breaching the Lower Snake projects could be significantly different if the John Day project was also modified. That is, the HIT wanted to examine whether economic costs of drawing down the four Snake River projects would vary significantly, depending on whether the John Day project was also subject to drawdown. The sensitivity analysis was undertaken to address the possible compounding effect of breaching all five projects. Another reason the John Day drawdowns were investigated here was the cost effectiveness of doing these hydropower studies at the same time the Snake River alternatives were being evaluated. The HIT was assembled and able to help guide the evaluation of the John Day drawdown alternatives along with the Snake River alternatives. The incremental costs of these sensitivity tests were very small and were considerably cheaper than doing an independent evaluation of John Day at a later date.

Table 5 provides a very brief description of the Snake River alternatives that were analyzed, and the sensitivity analysis alternatives that include drawdowns of John Day. See the Feasibility Report for more specific definitions of these alternatives.

Table 5
Alternatives Investigated

Snake River Alternatives	
Alternative A1 Base Case	Base Case as it is today. There is Columbia and Snake River flow augmentation, as described in the 1995 Biological Opinion.
Alternative A2	Future without drawdown condition. It assumes all fish passage is working with the lower Snake and John Day projects not drawn down, and includes improvements to the projects such as surface collectors and improved collection of juveniles for barging or release below the dam. Assumes Snake River spill for fish passage would be eliminated at Lower Granite, Little Goose, and Lower Monumental. Section 5.7.2 examines two variations of this alternative.
Alternative A3	Lower Snake projects drawn down to natural river levels. There is no change in flow augmentation from A1.
Alternative A5	Lower Snake projects drawn down to natural river levels and no Snake River flow augmentation. This alternative was not carried forward for evaluation by other workgroups.
Alternative A6a	Lower Snake projects are not drawn down and include project improvements similar to A2. Up to an additional 1 million acre-feet (MAF) of storage from the Upper Snake Basin is added for flow augmentation to the Base Case, for a total of 1,427 MAF.
Alternative A6B	Lower Snake projects are not drawn down and include project improvements similar to A2. No storage form the Upper Snake Basin is provided for Snake River flow augmentation. This is a reduction in storage from the Base Case of 0.427 MAF.

Sensitivity Analysis Alternatives	
Alternative B1	Lower Snake and John Day projects drawn down to natural river levels. There is no change in flow augmentation from A1.
Alternative B2	Lower Snake and John Day projects drawn down to natural river levels. There is no Columbia or Snake River flow augmentation.
Alternative C1	Lower Snake projects drawn down to natural river levels and John Day drawn down to the spillway crest. There is no change in flow augmentation from A1.
Alternative C2	Lower Snake projects drawn down to natural river levels and John Day drawn down to the spillway crest. There is no Columbia or Snake River flow augmentation.

As can be seen from the list of alternatives, several of the options include modifications to flow augmentation in the Columbia and Snake Rivers. The flow augmentation part of these alternatives consists of specific levels of flow to be provided at certain locations in the Columbia and Snake Rivers to enhance fish migration. These flow augmentation elements were considered because with the breaching of the Snake River (and John Day) dams current flow augmentation may no longer be needed to enhance fish migration. The revisions in flow augmentation, from the base case, will modify the operation of some or all of the storage reservoirs in the entire Columbia-Snake system. For this reason, the system hydro-regulation models identified not only the changes in flows and generation at the Snake River dams, but also all the other hydropower projects starting at Brownlee Dam on the Snake River and the Canadian Treaty projects on the Columbia River, and all downstream hydropower projects.

It is recognized that some of these alternatives may change through the remainder of this study process. For example, at least three configurations of alternative A2 are being considered. It is possible that the final selected A2 plan will have slightly different impacts on power (for example less power head at the 4 Lower Snake Dams). If this difference is significant enough, the analysis will be revised at a later date.

3.3 HYDRO-REGULATION MODELING RESULTS

This section describes the results of the two hydro-regulation models. The major output of the hydro-regulation models is the average monthly generation for each month and each water year, combined over all the system hydropower projects. The monthly generation data consists of 14 periods because the months of April and August are subdivided into two halves to reflect the significant differences in stream flows between the first half and second half of these months. The monthly generation data is also available for each hydropower project; however, the total monthly system hydropower generation serves as the major input to the economic analysis.

Table 6 summarizes the total monthly PNW system generation amounts for each of the alternatives as compared to the base case condition, Alternative A1. This table provides the monthly averages over all the water year simulations done by the HYSSR (60 years) and HYDROSIM (50 years). The table shows the total hydropower production in the PNW (System Generation). The HYSSR and HYDROSIM models have slightly different definitions of which hydropower projects are included in the PNW system generation, and hence the total system generation amounts are slightly different. These differences in system-wide hydropower generation estimates are used later in this analysis to define the economic effects of each alternative. However, the most important element of this study is the change in generation from the base condition, and the last section of this table shows how the difference between the two models. The last set of numbers in the table shows differences between the two hydro-regulation models are relatively small, on average, but can be significant for specific months and alternatives.

Table 6
HYSSR and HYDROSIM Results By Alternative
System Generation (aMW)

Alt	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann Avg	Percent of A1
HYSSR Results: Average Generation Over 60 Water-Year Simulations														
A1	9,466	9,520	10,414	14,071	16,800	15,200	13,820	15,846	18,729	18,834	13,725	11,997	14,038	
A2	9,467	9,533	10,418	14,078	16,803	15,203	13,820	16,006	19,049	19,139	13,743	12,008	14,108	
A3	9,046	8,953	10,021	12,867	15,987	14,098	11,794	13,437	16,314	16,703	12,728	11,280	12,771	
A5	9,317	9,107	10,494	13,253	16,230	14,247	11,796	13,261	16,078	16,538	12,450	10,851	12,805	
A6a	9,495	9,535	10,401	14,084	16,861	15,128	13,802	16,016	18,545	18,879	13,817	12,182	14,064	
A6b	9,412	9,504	10,437	14,042	16,840	15,088	13,819	16,081	18,578	18,755	13,731	12,011	14,028	
B1	8,703	8,519	9,377	11,534	14,535	12,461	10,337	11,977	14,693	15,114	11,842	10,650	11,647	
B2	8,062	8,706	10,658	12,285	15,902	14,038	11,387	11,342	14,100	13,794	11,289	9,549	11,734	
C1	8,866	8,764	9,767	12,217	15,311	13,320	11,045	12,640	15,430	15,820	12,283	10,988	12,208	
C2	8,384	9,085	11,059	12,814	16,506	14,992	12,243	11,936	14,419	14,467	11,713	9,687	12,276	
System Impacts--HYSSR (Generation Difference From A1; Negative Means Loss in Energy From A1)														
A2	1	13	4	7	3	3	0	160	320	305	18	11	70	0.5%
A3	-420	-567	-393	-1,204	-813	-1,102	-2,026	-2,409	-2,415	-2,131	-997	-717	-1,267	-9.0%
A5	-149	-413	80	-818	-570	-953	-2,024	-2,585	-2,651	-2,296	-1,275	-1,146	-1,233	-8.8%
A6a	29	15	-13	13	61	-72	-18	170	-184	45	92	185	26	0.2%
A6b	-54	-16	23	-29	40	-112	-1	235	-151	-79	6	14	-10	-0.1%
B1	-763	-1,001	-1,037	-2,557	-2,739	-2,739	-3,483	-3,869	-4,036	-3,720	-1,883	-1,347	-2,391	-17.0%
B2	-1,404	-814	244	-1,786	-1,162	-1,162	-2,433	-4,505	-4,629	-5,040	-2,436	-2,448	-2,304	-16.4%
C1	-600	-756	-647	-1,854	-1,880	-1,880	-2,775	-3,206	-3,299	-3,014	-1,442	-1,009	-1,832	-13.1%
C2	-1,082	-435	645	-1,257	-208	-208	-1,577	-3,910	-4,310	-4,367	-2,012	-2,310	-1,762	-12.6%
HYDROSIM Results: Average Generation Over 50 Water-Year Simulations														
A1	10,572	11,558	12,735	15,935	19,669	16,435	14,858	17,777	20,487	19,960	15,333	13,108	15,702	
A2	10,572	11,558	12,735	15,935	19,671	16,435	14,858	17,927	20,732	20,202	15,343	13,108	15,756	
A3	10,183	10,865	12,244	15,031	18,677	15,324	13,057	15,676	18,168	17,923	14,220	12,352	14,477	
A5	10,596	11,200	12,421	15,492	19,328	15,469	13,042	15,436	17,906	17,776	13,694	11,837	14,516	
A6a	10,503	11,562	12,752	15,940	19,684	16,466	14,830	17,708	20,544	20,137	15,405	13,622	15,763	
A6b	10,518	11,637	12,787	16,037	19,708	16,468	14,890	17,745	20,453	19,888	15,285	13,009	15,702	
B1	9,547	10,317	11,581	13,812	17,070	13,893	11,852	14,171	16,492	16,337	13,306	11,681	13,338	
B2														
C1	9,841	10,622	11,970	14,401	17,914	14,614	12,422	14,898	17,232	17,038	13,718	11,993	13,889	
C2														

System Impacts--HYDROSIM (Generation Difference From A1: Negative Means Loss in Energy From A1														
A2	0	0	0	0	2	-1	0	150	245	241	11	0	54	0.3%
A3	-389	-693	-491	-904	-992	-1,111	-1,801	-2,101	-2,319	-2,037	-1,112	-755	-1,225	-7.8%
A5	24	-358	-315	-444	-341	-967	-1,816	-2,340	-2,581	-2,185	-1,639	-1,271	-1,186	-7.6%
A6a	-69	5	16	5	14	30	-28	-68	57	177	72	514	61	0.4%
A6b	-54	79	52	102	38	33	32	-31	-34	-72	-47	-99	0	0.0%
B1	-1,025	-1,240	-1,155	-2,123	-2,599	-2,543	-3,006	-3,606	-3,995	-3,623	-2,026	-1,426	-2,364	-15.1%
B2														
C1	-731	-936	-765	-1,534	-1,756	-1,821	-2,436	-2,878	-3,255	-2,922	-1,615	-1,114	-1,814	-11.5%
C2														
Differences in Impacts Between HYSSR and HYDROSIM Negative Means HYSSR Difference is Larger														
A2	-1	-13	-4	-7	-1	-4	0	-10	-75	-64	-7	-11	-16	-0.1%
A3	31	-126	-98	300	-179	-9	225	308	96	94	-115	-38	42	0.3%
A5	173	55	-395	375	229	-14	208	245	70	111	-364	-125	47	0.3%
A6a	-99	-11	29	-8	-46	102	-9	-238	241	131	-19	329	34	0.2%
A6b	0	95	29	131	-2	145	33	-266	117	7	-53	-112	10	0.1%
B1	-262	-239	-118	414	-334	196	477	263	41	97	-143	-80	27	0.2%

Technical Exhibit A, at the end of this report provides the system generation amounts for each of the water years. Appendix ____, Hydrology and Hydro-Regulations, of the Lower Snake River Juvenile Mitigation Feasibility Study provides detailed description of the hydro-regulation models and study results.

4.0. POWER SYSTEM MODELING

4.1 EVALUATION PROCESS

The hydroelectric dams on the Columbia and Snake Rivers are the foundation of the Pacific Northwest's power supply. Electricity is also exported out of and imported into the PNW over intertie transmission lines to regions all over the western United States, Canada and Mexico. This widespread nature the western electricity system is accounted for in this analysis.

In the past several years the entire electrical industry has been undergoing drastic changes from a regulated industry of the past into a partially competitive industry. The passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Energy Policy Act of 1992 (EPACT) allowed new entities to acquire generation facilities and to provide electrical energy for sale to electric utilities. These laws paved the way for the industry's transformation by effectively eliminating barriers previously existing in the domain of power generation. Opening electricity generation to competitive market forces represents the core for the transformation and restructuring activity that has been implemented.[1]

Another major step towards the competitive market system occurred on April 24, 1996, when the Federal Energy Regulatory Commission (FERC) issued a final rule, Order No. 888, in response to provisions of EPACT. Order No. 888 opened wholesale electric power markets to competition by requiring utilities that own, control, or operate transmission lines to file non-discriminatory open access tariffs that offer others the same electricity transmission service that they provide themselves. Open transmission access improves the flexibility to purchase electricity from generation facilities in the Pacific Northwest (PNW), the Pacific Southwest (PSW), and other WSCC areas. In early 1998 the State of California implemented significant legislation to set up a formal market system in which a wide range of wholesale buyers and sellers can contract for electricity sales.

The domestic power market has two distinct segments - wholesale and retail. The wholesale market covers the actual purchase and sale of electricity to resellers (who sell to retail customers), in-kind exchanges of electricity, and transmission services along with ancillary services needed to maintain reliability and power quality at the transmission level. The retail energy market is where electricity and other energy services are sold directly to all end-use customer classes (*i.e.*, residential, commercial, industrial, and others). Since Federal power is not marketed to retail consumers (with the exception of the some industries), the focus of this analysis is on the wholesale market. Changes in wholesale markets will of course affect retail markets, but the impacts will vary for each utility. This analysis does not investigate the retail effects because it is beyond the scope to track impacts within each power utility.

The factors that lead to wholesale (inter-utility) trade in electric power include differences in resource availability, load patterns, and generation costs. For example, abundant water resources to produce hydroelectric power in a given region may make hydroelectricity in that region less expensive than other sources of electricity, especially if the other fuels have to be transported over long distances. Wholesale power transactions include purchases, sales for resale, exchanges, and wheeling (*i.e.*, transmission services). These wholesale power transactions involve the buying of power and energy from electric utilities and regional power marketing agencies (*e.g.*, BPA).

With expansion of active competitive markets for electricity, the previous simplified system power models used by the Corps of Engineers, BPA and others were no longer sufficient to identify the net economic effects of changing the supply of hydropower energy and capacity. Because of the inter-related, market driven nature of the electric industry, it was decided that the evaluation of changes in hydropower production in the PNW must be evaluated on a system-wide basis. This study uses two separate system production cost models, one by the Corps and one by BPA, to evaluate the net economic effects of changing power generation at the four Lower Snake Dams and John Day. A third approach developed by the Northwest Power Planning Council (NPPC) was also utilized in this study.

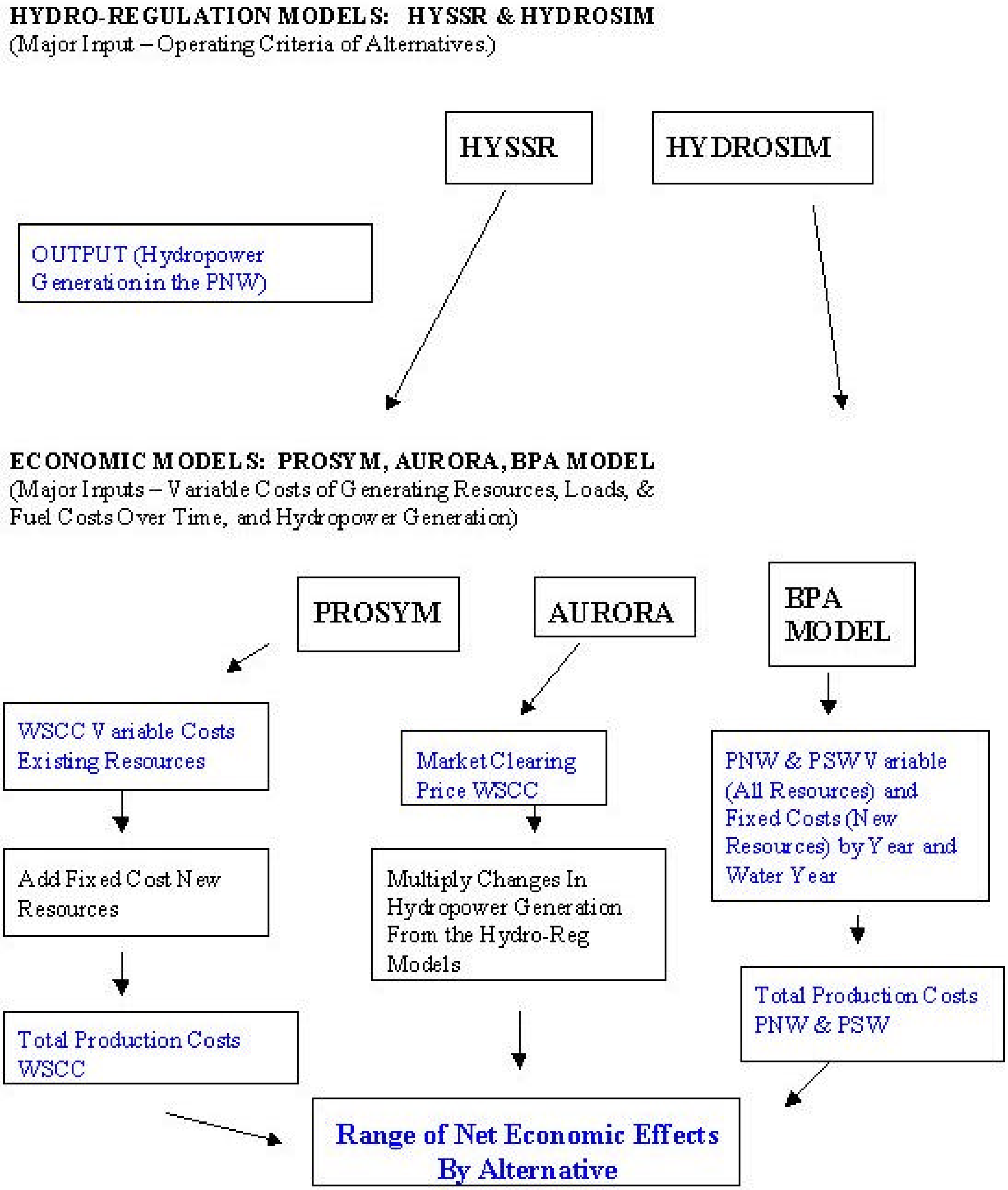
These multiple approaches were undertaken to look at the impacts from different analytical viewpoints to assure that the economic effects are adequately bracketed in the final estimates. The study progressed by examining model results for each alternative with the different system approaches. To the extent possible the basic input assumptions were standardized among the models, and these assumptions are discussed below. Upon comparing results, the study team built a consensus on the best analytical approach.

To assist the study participants in accessing alternative evaluation approaches a simplified spreadsheet model was developed. This spreadsheet model was made available for use by any interested party. This simplified model included the different hydropower generation impacts by alternative, the monthly market-clearing prices as derived by the NPPC, and the ability for the user to input his/her own values to test different results.

4.2 SYSTEM MODEL DESCRIPTIONS

The study team used several models in the analysis. Section 3 described the hydro-regulation models and this section describes the economic models. Figure 9 provides a schematic of how the several models were integrated to estimate the range of net economic effects. Specifics of each model are provided below. In general, the results from the hydro-regulation models were fed into the economic models. Each economic model provided somewhat different outputs, so additional analysis was added to model results to define the net economic effects.

FIGURE 9 SCHEMATIC OF MODELS USED IN HYDROPOWER ANALYSIS



The evaluation of the net economic effects on hydropower was based on two basic approaches: a market price analysis and a system production cost analysis. The AURORA model served as the basic tool for the market price analysis, and the PROSYM and BPA models were used for the system production costs analysis.

It is important to note that the market price and system production cost approaches are intended to measure the same net economic effects, and hence are directly comparable.

Many similarities do exist in the three models used in this analysis. They are all designed to identify how the different power generating resources will be operated to meet projected power loads (demand). They do vary in scope from hourly models (Aurora and PROSYM) to a monthly model that stratifies hours in the month into different blocks of peak and non-peak hours. The geographic regions covered by each model are different. The treatment of constructing new power resources and retiring power plants varies among the models. The primary outputs of each model are different. The Aurora model identifies the marginal cost in each period and this is assumed to be the market-clearing price. PROSYM provides the production costs (variable costs) to meet loads by all regions in the WSCC. The BPA model also identifies production costs but, in addition it provides the fixed costs of new resources to arrive at the total system production costs.

4.2.1 Market Price Approach. The conceptual basis for evaluating the benefits from energy produced by hydropower plants is society's willingness to pay for the outputs, which sometimes can be obtained through market prices. Using market-pricing techniques for power evaluations at the consumer level had in the past been problematic for the following reasons. To use market pricing as the economic benefit it must be demonstrated that the consumer's rates are based on the marginal production costs which was not typically the case in the west coast region. Changes in hydropower supply had to be too small to influence market price. The market price approach for power benefits would also have financial comparability problems with other benefit categories because of the problem of equating interest rates, insurance, and taxes. That is, the computation of economic effects for recreation, navigation, *etc.* was based on a fixed discount rate and no insurance or tax costs. The market pricing of power inherently includes these elements at varying levels for different entities, and separating these out was difficult. However, with the movement towards a competitive market, the wholesale price of electricity in the California market and elsewhere is being priced at or near the marginal production cost of the last resource to provide the needed electricity. So, this part of the power analysis looks at valuing the incremental changes of hydropower generation at the wholesale market price, which is based on the marginal cost of the last resource used to meet load in the specific time frame.

As more competitive electricity markets develop, prices will not be set to average costs as they have been in the past. Rather, the various services provided--operating reserves, voltage stabilization, etc.--will be available and priced separately. However, consumers will not have to purchase all of these services from separate suppliers. During most time periods in the power spot market, the generation price of electricity will be set by the operating costs of the most expensive generating unit needed to meet demand, or what is referred to in economics as the "marginal cost" of production. In general, a supplier will not be willing to sell power below the market price of the most expensive facility operating at a given time, because consumers will be willing to pay the higher price. Similarly, consumers will be unwilling to pay more than the cost of the most expensive operating available generator, since other suppliers will be offering lower prices. With prices set to marginal costs, the market will clear: all suppliers willing to provide power and all consumers willing to purchase power at the market price will be doing so.[2]

Market prices were obtained from the NPPC study entitled *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June, 1998.* In developing the market price forecasts, the NPPC relied principally on a proprietary model called Aurora that was developed by Electric Pricing Information Services, Inc (EPIS. Aurora is designed specifically to model wholesale electricity prices in a deregulated generation market. The general elements of the Aurora model are provided here, and a more thorough description of Aurora is contained in the NPPC's study, which is attached as Technical Exhibit B.

In a deregulated generation market, economic theory says that prices at any given time should be based on the marginal cost of production. In a competitive electricity market, prices will rise to the point of the variable cost of the last generating unit needed to meet demand. This is the economic model currently in use in the California Power Exchange. One of the principle functions of Aurora is to estimate this hourly market-clearing price at various locations within the WSCC.

Aurora estimates prices by using hourly demands and individual resource operating characteristics in a transmission-constrained chronological dispatch algorithm. The operation of resources within the WSCC is modeled to determine which resources are on the margin for each area in any given hour.

In Aurora, the WSCC is broken into 12 geographic areas largely defined by states, with the exception of California, which is split into a northern and southern area, and Oregon and Washington, which are combined into one area. Long term average demand and hourly demand shapes for these regions are input. These demand regions are connected by transmission links with specified transfer capabilities, losses and wheeling costs.

Existing supply-side generating units, approximately 2000 of them in the WSCC, are defined and modeled individually with specification of a number of cost components and physical characteristics and operating constraints. Hydro generation for each area, with instantaneous maximums, off peak minimums, and sustained peaking constraints are also input. Demand side resources and price induced curtailment functions are defined, allowing the model to balance use of generation against customer demand reduction alternatives.

Aurora uses this information to build a least cost dispatch for the WSCC. Units are dispatched according to variable cost, subject to non-cycling and minimum run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market clearing price for the power they generate.

The hourly market clearing prices are developed on an area-specific basis. The analysis for this report uses the Oregon/Washington area price to value PNW generation. This price can be interpreted as the average busbar price as seen by generation in the OR/WA area. Charges for delivery within the OR/WA area are not included in the price.

Aurora also has the capability to simulate the addition of new generation resources and the economic retirement of existing units. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources will only be built when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, *i.e.*, the ability of investors to recover fixed and variable costs with an acceptable return on investment. Aurora uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules. This effectively results in construction and retirement decisions being based on "perfect knowledge" of future prices.

Existing units that can't generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas of the WSCC, the rate at which existing units can be retired for economic reasons is constrained in these studies.

4.2.2 System Production Cost Approach. The other approach to define net economic effects was a system production cost analysis. The economic effects were identified by comparing system production costs with the level of hydropower production from the different alternatives being investigated. Changes in hydropower generation result in different levels of operation of more costly thermal generating power plants. Hence, the economic values of different increments of hydropower energy were defined by the displacement of thermal resource generation.

For this analysis the total system production costs are defined as the sum of the variable operating costs (production costs) and the fixed costs (annualized capital costs) of new resources added to meet loads. The total system is defined by different geographic regions in each model. However the basic definition is

Total System Production Costs =	Variable Costs	+ Fixed Costs
	(Production)	(New Capacity)

Both BPA and the Corps have models that estimate the costs of meeting energy demand (loads) with available hydropower energy and thermal resources. The models identify the most cost-effective way to meet loads given all system constraints. These models estimate which resources will be operated to meet loads and the variable costs of these resources are summed to define variable production costs. Loads may also be met through purchase of energy from the PNW, PSW, or other regions. The purchase price reflects the variable generation costs and the transmission costs of the resource used to provide the energy. Production costs in the PNW and PSW will vary depending on how much Columbia River hydropower is generated. The output of hydro-regulation models (HYSSR and HYDROSIM) served as the major input to the system energy production cost models. The system production cost models identified what resources would be used to meet load, and hence the models could be used to define which resource was used to meet the last increment of load (marginal costs) in each time frame. Therefore, these models could be used for both the market valuation and system production cost approaches. The Aurora model described above is essentially a system production cost model, but its primary output is the marginal costs in each period.

Table 7 provides a description of the major concepts of the BPA model. The model categorizes West Coast thermal resources into several production cost blocks based on the average efficiencies of the plants. The more inefficient plants tend to be the older plants that are operated last in the dispatch order. The BPA model compares the PNW and PSW loads to the monthly hydropower and thermal generation for each simulation year. As hydropower generation varies, the thermal generation amounts and costs change. The model identifies the marginal costs of the resources which hydropower will displace. The load is broken into three distinct periods of each week or month. These periods are the super peak (hours 7 a.m. to 10 a.m. and 5 p.m. to 8 p.m. each weekday), peak (hours 6 a.m. to 10 p.m. Monday through Saturday, not including the super peak hours) and non-peak hours (the remainder of the week). This stratification accounts for the significant variations in prices and resources used to meet loads in these different periods of the week.

Table 7
BPA's Regional Power Spreadsheet Model

Model Philosophy and Use

- Underlying philosophy is that the future value of electricity in the PNW will be determined by the cost of operating the next available West Coast resource--either operation of existing resources or construction and operation of new resources.
- Model has a PNW and a PSW region. Canada and the Inland SW are not modeled.
- Model attempts to meet West Coast loads with West Coast resources. Each region's resources are used to meet its own loads. If the PNW has surplus resources, they are available for sale to the PSW. If the PNW is deficit, PSW resources are available for purchase (both transactions subject to intertie limits).
- Model calculates results on a monthly basis, but is also capable of dividing the month into super peak, peak and non-peak hours. Currently, super peak hours consist of 30 hours per week, peak hours consist of 66 hours per week, and non-peak hours consist of 72 hours per week.
- Results consist of the total cost for operating the West Coast regional electric system. Total costs include variable costs of all resources and the fixed costs for any new resources. Other outputs consist of the marginal cost for meeting an increment of PNW load, PNW load/resource balances, operation of specific resource blocks, and many other outputs.

Existing System

- The PNW region consists of information on PNW loads and resources. PNW resources are divided into six groups: non-displaceable (nuclear, renewables, etc.); low cost coal (mostly east-side coal plants); high cost coal, existing single cycle combustion turbines (CTs), existing combined cycle combustion turbines (CCs) and imports.
- The PSW region consists of information on PSW loads and resources. PSW resources are grouped into two categories: displaceable and non-displaceable. Further, displaceable PSW resources are defined by their heat rates. A supply curve of PSW resources by heat rate is developed in the model.
- Data for both regions consist of existing loads, existing resources, variable cost of operating existing displaceable resources, current and future gas prices.
- Data for the PNW includes monthly hydro generation based on 50 historical water years.
- Data for both regions includes the cost for failing to meet native loads (cost of unserved load).

New Resources
• The model has a limited optimization routine based on the following philosophy: new resources will be built when they are less expensive to build and operate than the combination of the cost of operating existing resources and curtailing load, when no other resources are available. Existing resources consist of both supply and demand side resources. The only future resource choice is new combined cycle combustion turbines (CCs).
Operations
• Model operates from a PNW perspective. Model checks whether or not PNW is surplus or deficit given operation of all existing and new resources. If surplus, dispatch logic (hardwired in model) is as follows: Displace all PNW existing CT resources. Displace all PNW high cost coal resources. Sell to PSW (given intertie and market limits). Displace all PNW existing CC resources. Displace all PNW new CC resources. Displace all PNW low cost coal resources. Displace imports. If deficit, model buys from the PSW (given intertie limits and PSW resource availability). If no PSW resources available, model purchases available demand side resources, and then curtails PNW load.
Uncertainties
• Model handles uncertainty in PNW hydro by modeling 50 years of historic hydro information. • Model has three different load forecasts for the PNW and PSW--low, medium and high. • Model has three different gas price forecasts for the PNW and PSW--low, medium and high.

The Corps utilized an existing proprietary hourly system production model entitled PROSYM, which has been used extensively by the Corps throughout the United States. PROSYM was developed and is maintained by Henwood Energy Services of Sacramento, California. The Corps of Engineers (CENPW-NP-ET-WP) used the model under a contract with Henwood. The Corps has utilized this model, and its TVA-developed predecessor, for a number of years. Table 8 provides a description of the major concepts of the model. The PROSYM model has an extensive database, which includes operating characteristics of all WSCC power plants, current fuel prices, plant efficiencies, and inter-regional marketing conditions. The model dispatches thermal and hydropower resources on an hourly basis to meet energy demand. Hydropower resources are based on weekly energy amounts generated by the hydropower regulator models from the projects in the study region, or weekly energy amounts input to the model. The model dispatches the hydropower to follow loads to capture the daily peaking capability of hydropower. This model was used to examine in great detail selected water years. The model also includes a pollution emissions subroutine.

Table 8
Corps of Engineers' Use of PROSYM Model

Model Philosophy
• Simulates a power system operation on a chronological hourly basis. • Simulates a year hour-by-hour, in one-week increments. • Used to define power system operating costs (variable costs of operating resources) to meet loads. • Operating costs for each plant include fuel costs, variable operation and maintenance costs, and startup costs. • Meets hourly loads in the most economic manner possible given a specified set of generating resources. • Recognizes operating constraints imposed on individual units.

Existing System Simulation

- Uses external data (like HYSSR output) to define hydropower week-by-week generation.
- Data utilized for thermal plants include: unit capacity, fuel type, number of units per plant, ramp rate, fuel cost, minimum and maximum unit output, minimum down time, variable heat rate, forced outage rate, minimum up time, start-up costs, maintenance schedule, on-line date, retirement date, categorization by type such as base load, intermediate, or peaking.
- Dispatched in order of increasing energy costs, unless fuel supply contracts or other factors require a specific dispatch.
- After units are dispatched, a probability distribution is used to develop forced outages, and contingent resources are then dispatched.
- Hydropower inputs required: (Can define numerous types of hydropower units)
    - Required minimum continuous output
    - Normal maximum output
    - Energy output for each week
    - Peaking output
    - Pump storage characteristics
- Multi-area capability allows for bi-directional line limits, transmission losses, and wheeling charges. Unit commitment and dispatch is fully "transmission-network aware."
- Can incorporate area-level operating reserve requirements.
- Calculates the marginal cost data for each transmission area.

New Resources

- User specifies new resources to meet load if existing resources are inadequate.
- Planned resources can be modeled to come online at specified dates in the future.

Operations

- Uses extensive Regional Databases developed from unrestricted sources such as FERC filings, NERC reliability councils, state regulatory and planning commissions, *etc.*
- Output is production costs by resource to meet weekly load.
- Output available by regions, by plants, and by plant types.
- Includes a pollution emission subroutine that estimates emissions with each scenario.

The model refinements were an ongoing process. As model improvements were made, the economic evaluation process evolved based on BPA, Corps, and Hydropower Impact Team guidance.

4.3 MODEL INPUTS

This section describes the major inputs utilized by the system production cost models and the market price analysis.

4.3.1 System Loads. The system loads, or power demands, were taken from several sources. It was decided by the HIT to utilize the load projections developed by the NPPC as the primary source of load projections. The basic load assumptions developed for the NPPC's 1998 study, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June* (Provided in Technical Exhibit B), were used where possible in the power system models.

The Aurora model was used by NPPC in the referenced study, and this model was driven by hourly electricity demand in its 12 regions in the west. These regions are similar to, but not the same as, those utilized in the Corps PROSYM model. The average load forecast was broken down into monthly, weekly, and hourly loads based on the typical load shape for all hours of the year. It was assumed that hourly composition of demand does not change except to the extent demand-side peaking resources reduce peak demand. The peak load is the maximum hourly demand placed on the system in any given year. NPPC used the hourly composition factors embedded in Aurora. A check of those factors against available data and some results from the Council's Load Shape Forecasting System showed the Aurora factors to be reasonable. Starting year demands were taken from WSCC data and allocated to regions (mostly states) based on historical sales data. Table 9 shows the starting 1997 loads for each of the 12 Aurora demand regions.

Table 9
Aurora Model
1997 Electric Loads by Demand Region

Region	Load (aMW)
OR/WA	16,779
North CA	10,730
South CA	16,783
Canada	11,842
ID	2,644
MT	1,554
WY	1,455
CO	4,681
NM	2,106
AZ	6,474
UT	2,481
NV	2,817
Total	**80,346**

Source: NPPC's study,
Analysis of the Bonneville Power Administration's
Potential Future Costs and Revenues, 5 June

The load forecasts project the PNW demand in terms of average megawatts by year up to year 2020. Demand was assumed to grow at equal rates in all of the demand areas. Although this will certainly not be the case, the team did not research every state's demand forecasts because these were likely to include a wide range of basic demographic assumptions. It was also felt that historical relative growth rates for states might not be a good indicator of future demand growth.

For the medium case, demand was assumed to grow at 1.5 percent annually. In the low case, the assumption was 0.5 percent per year, and in the high case it was 2.5 percent. The significance of these assumptions are addressed in the Risk and Uncertainty section of this report.

4.3.2 Fuel Prices. The major component of production cost of any power system is the costs of fuels expended to generate the electricity. Hence, the fuel prices assumed to occur over time are a critical element of the system production cost modeling and the market price analysis. This section describes the assumptions made for the fuel prices in the different regions of the WSCC. The initial analysis used the medium forecast, and the Risk and Uncertainty section describes how alternative projections were utilized.

As with the load projections, the HIT resolved to utilize the work of the NPPC in their study, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June.* This study was widely coordinated with regional power interests and had considerable scrutiny.

4.3.2.1 Natural Gas Prices. The NPPC Aurora model is currently structured to develop its natural gas price assumptions based on two pricing points, Henry Hub in Louisiana and Permian in Texas. Prices in the Aurora regions are then based on a series of differentials from these trading hubs. There are three basic assumptions that need to be specified to provide all of the natural gas information:

- starting prices for 1997 at the two pricing hubs;
- a series of basis differentials to develop regional prices; and
- real escalation rates for the prices at the two market hubs.

The starting natural gas price for the Aurora analysis should be close to an equilibrium price under normal weather conditions. Actual prices for 1997 were found to not be a good starting point because gas prices were at a cyclically high level in 1996 and 1997. Henry Hub spot prices averaged $1.78 per million Btu from 1989-95 but extraordinarily high prices in February and March of 1996 sent the average 1996 price up to $2.76. Prices remained relatively high during the winter of 1996-97 and the average 1997 price was estimated to be around $2.50.

Figure 10 shows Henry Hub spot gas prices from 1989 to 1997. These prices averaged $1.62 between 1989 and 1991, $1.89 between 1992 and 1995, and $2.65 for 1996 and 1997. The recommended starting price used by NPPC for the medium case was $2.00 for Henry Hub. This is about equal to the average price between 1989 and 1997. This level recognizes some upward trend in Henry Hub spot natural gas prices in the past ten years and is probably more representative of a long-term gas price level for 1997.

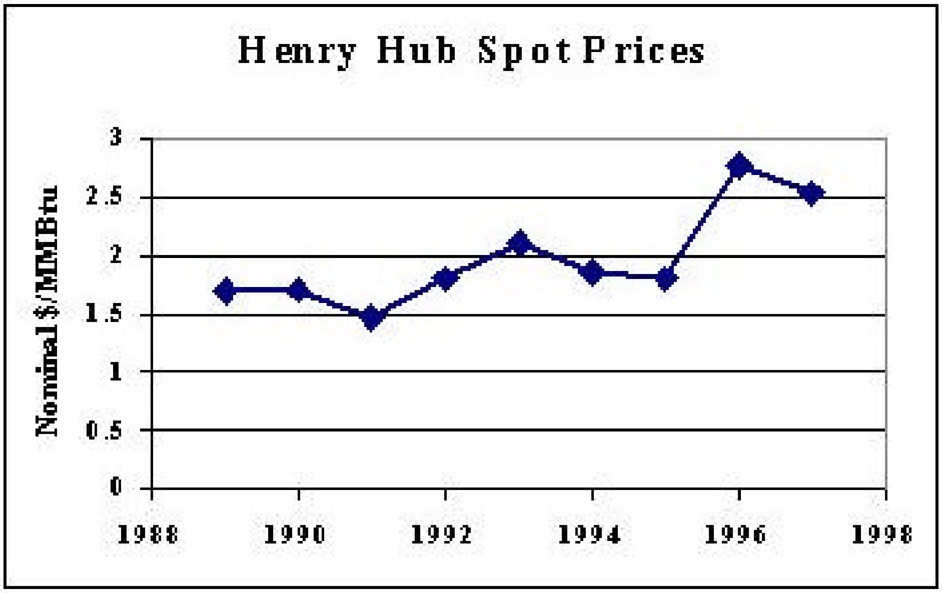


Figure 10: Henry Hub Natural Gas Prices

Permian prices are typically less than Henry Hub prices. Between 1989 and 1995 Permian prices averaged $.11 per million Btu less. However, the differences had been increasing toward the end of that period and were about $.22 in 1994 and 1995. In 1996 with the large increase in Henry Hub prices the difference was $.45. These differences are illustrated in Figure 11. The NPPC used a starting difference of $.20 so that the 1997 Permian price is $1.80 per million Btu.

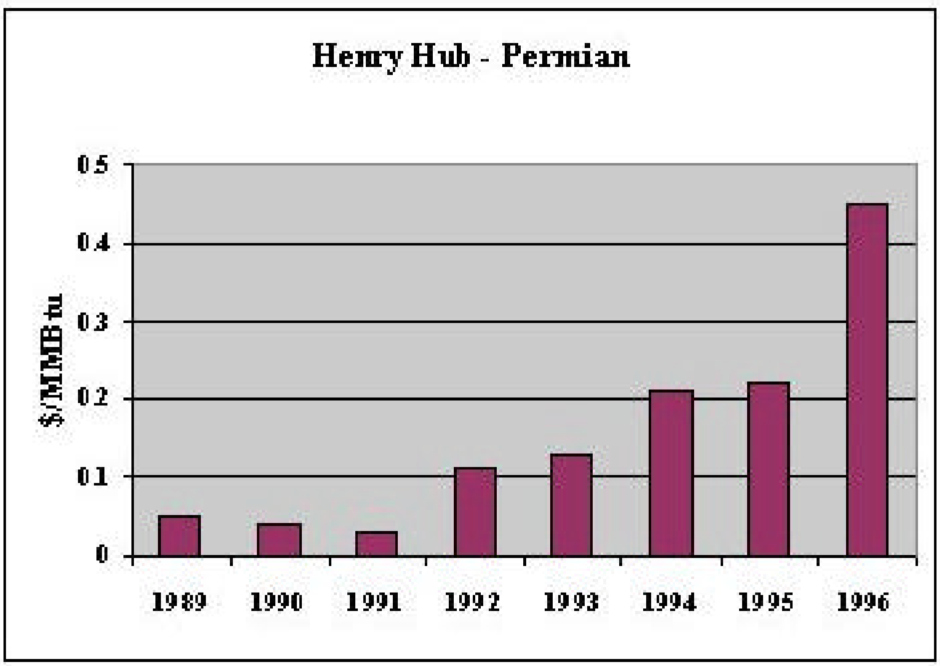


Figure 11: Natural Gas Price Differences Between Henry Hub and Permian

The basis differentials from Henry Hub and Permian to the other Aurora regions were estimated based on various data sources. The major issue to be dealt with was the lower prices associated with Canadian and Rocky Mountain gas supplies. The choice of a typical value for this difference is also confused by the very volatile and unusual patterns of the past few years. Figure 12 illustrates the problem. Canadian prices at the British Columbia (B.C.) border at Sumas were typically $.30 to $.60 lower than Henry Hub prices until 1996. When Henry Hub prices increased in February 1996, Western Canadian and Rocky Mountain, prices did not. As a result the differential in prices increased to $1.38 on an annual basis in 1996. When Henry Hub prices peaked again in December 1996, Canadian prices increased even more causing the differential to drop to near zero in that month. Clearly these markets were not in equilibrium in the last two years, and judgement was needed to select the most appropriate adjustments for these regions.

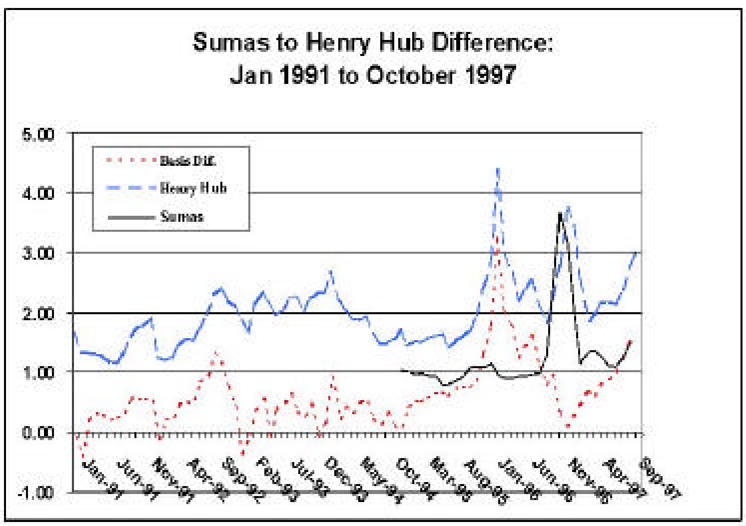


Figure 12: Natural Gas Price Differences

Tables 10 and 11 show the starting prices for the two market hubs, the differentials to derive the Aurora regional prices and the estimated price for 1997 for each of the Aurora areas.

Table 10
Natural Gas Price Differentials from Henry Hub
Adjustments and Selected Prices for 1997

		Differential	Estimated Start Price
Henry Hub Price = $2.00			
Sumas		-0.55	$1.45
	Canada	0	$1.45
	NW Sumas	0.25	$1.70
AECO		-0.65	$1.35
	NW AECO	0.28	$1.63
	Northern CA	0.6	$1.95
San Juan		-0.3	$1,70
	UT	0.1	$1.80
	CO	0.25	$1.95
	WY	0.1	$1.80
	MT	0.3	$2.00
	ID	0.27	$1.97

Table 11
Natural Gas Price Differentials From Permian
Adjustments and Selected Prices for 1997

		Differential	Estimated Start Price
Permian Price = $1.80			
CA Border		0.1	$1.90
	Southern CA	0.25	$2.15
AZ		0.3	$2.10
NM		0.15	$1.95
NV		0.2	$2.00

The final assumption for natural gas prices was the real escalation rate applied to Henry Hub and Permian prices. For the medium case, the gas price escalation included in the Council's power plan was assumed to be 0.8 percent per year escalation above general inflation. The low forecast assumed a -1.0% real escalation rate, while the high projection assumed +2.0% real escalation. These assumptions translate into similar growth rate in all regions with one exception. In 1999 and 2000 significant expansions to pipeline capacity to export from Alberta to the East are expected to come online. This expanded export capacity will have the effect of increasing prices in Alberta and British Columbia, perhaps significantly. To reflect this it was assumed that the basic differential from Canadian markets to Henry Hub decreases in the medium case. The Alberta Energy Company (AECO) Hub price in Alberta decreases from $ -.65 to $ -.45 by the year 2001. The Sumas differential decreases from $ -.55 to $ -.40 during the same period. These differential decreases result in significant increases to Northwest natural gas prices in the early years of the analysis. A range of natural gas assumptions is explored in the analysis as presented Table 12.

Table 12
Summary of Natural Gas Price Assumptions

	Low	**Medium**	**High**
1997 Price			
Henry Hub Permian	$1.80 $1.60	$2.00 $1.80	$2.25 $2.15
Basis Differential			
AECO Sumas	-.65 constant -.55 constant	-.65 down to -.45 -.55 down to -.40	-.65 down to -.20 -.55 down to -.10
Escalation Rates	-1.0%	+0.8%	+2.0%

4.3.2.2 Oil Prices. Aurora contains prices for various types of oil including crude oil and number 1 through 6 fuel oils. In the default Aurora data base, the prices of all of these oils are set at $3.00 per million Btu (MMBtu) for the 1997 base year. Crude oil was assumed to have no escalation, but the fuel oils all had 1.3 percent real escalation rates. $3.00 was judged to be a reasonable starting price for crude oil, since it was about the average price since the late 1980s. However, there is a systematic difference among the various oil products and crude oil that depend generally on the cost of refining necessary to convert crude oil into the other products. Figure 13 shows these relationships for 1980 to 1996.

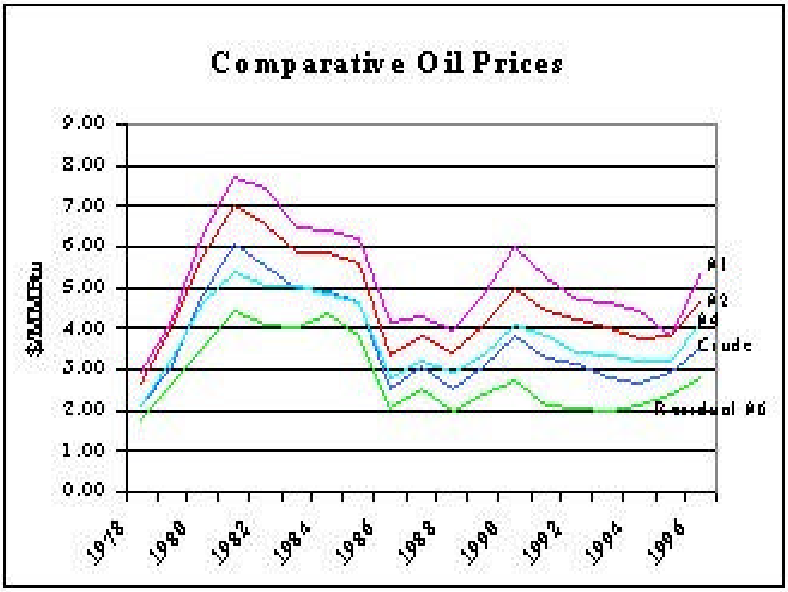


Figure 13: Historic Oil Prices by Fuel Product

Based on the fact that oil prices are fairly high in 1996 and 1997, it was decided to use the starting crude oil prices at $3.50 per MMBtu with a low real escalation rate of 0.5 percent per year. This escalation rate can be applied to all oil fuels. Applying average differences that are illustrated in Figure 13, the 1997 starting values that were selected for other oil fuels are shown in Table 13.

Table 13 Fuel Oil 1997 Prices Used in Analysis	
Fuel Oil Type	**1997 Price ($/MMBtu)**
Crude Oil	$3.00
#1 Fuel Oil	$5.00
#2 Fuel Oil	$4.50
#3 Fuel Oil	$4.25
#4 Fuel Oil	$3.85
#5 Fuel Oil	$3.50
#6 Fuel Oil	$2.70

Because oil prices do not appear to play an important role in determining the future market price of electricity, oil prices ranges were not used in the analysis.

4.3.2.3 Coal Prices. The other fuel, besides natural gas, that plays a significant role in the market price of electricity is coal. It was assumed that coal prices would decline in real terms in the base and low cases and to remain constant in the high case. In the low case coal prices were assumed to decline by 2 percent a year. In the base case, they decline at 1 percent a year. These growth rates were based on the Energy Information Administration's Annual Energy Outlook.

4.3.3 Resources; Existing and Future. Tables 3 and 4 above summarize the electrical generation resources in the PNW region and the total WSCC. These existing resources will be insufficient to meet loads in the future if load growth occurs as projected. This is particularly true in the lower water years and peak demand periods after year 2002. Therefore, it was necessary to project what kind of resources will be built in the future, and under what conditions these will be built. Each of the three models used in this analysis approached the addition of new thermal resources in different manners. The assumptions used to determine when new resources will be added under each of the alternatives are provided in section 5.4 below.

The type of resources to be added to the system was reviewed by the study team. It was found that the most predominate type of thermal plants that have been recently added to power systems on the West Coast has been natural gas-fired combined-cycle combustion turbine (CC) plants. This trend has been confirmed by CENWD-ET-NP-WP in several studies throughout the United States. It was found that CC natural gas plants represented the most cost-effective new additions over a wide range of potential plant factors. Additional studies were done by NPPC to identify the most likely new resources. The Aurora model was run adding several potential types of resources such as combustion turbines, combined cycle, and coal plants, along with conservation. In almost all scenarios, through 2015, the most economical expansion of the power system was with combined cycle plants powered by natural gas. The NPPC Power Plan also concluded that because of their low cost, abundance of suitable sites, and favorable technical and environmental characteristics, natural gas-fired combined cycle power plants are the most likely new bulk power generating resource. For the reasons stated above it was assumed in the Corps and BPA models that all new thermal resources to be built through year 2020 would be natural gas-fired combined cycle power plants.

The NPPC as part of its Power Plan responsibilities keep abreast of the latest construction and operating costs for all potential resources. The construction costs identified for CC plants of 250 MW capacity in the West Coast region were estimated to be $601per kW of installed capacity, at the 1998 price level. The average heat rate of the new CC plants in 1998 was assumed to be 7,045 Btu/kWh. This heat rate was assumed to go down over time at the rate of change described in section 4.3.4 below. The construction costs were based on the most recent financing experienced by the industry. The Corps of Engineers evaluates capacity costs based on procedures that were developed by the Federal Energy Regulatory Commission (FERC). These procedures identify the construction costs of different resources based on the current Federal discount rate (6.875%) and specific assumptions about taxes and insurance. Using the FERC process the plant construction costs of a 150 MW CC plant was $622/kW, and the costs of a 225 MW CC plant was $615/kW. The FERC database did not include costs for a 250 MW CC plant, but it can be assumed that construction costs would be somewhat less than the $615/kW costs and probably will approach the $601 costs identified by the NPPC. So, for all practical purposes these different construction costs (with different financing assumptions) are sufficiently close to ignore any differences. For this reason, all CC construction costs were assumed to be $601/kW. The annualized value of these construction costs was based on recent industry interest rates for the BPA model and the Aurora model. To include these costs in the annual simulations, the construction costs were adjusted to an annual fixed cost amount. The fixed costs used in the BPA model were in the 11.4 to 11.9 mills/kWh range, depending on the year of simulation.

For comparison purposes the annualized values of the construction and fixed O&M costs for gas powered combined-cycle powerplants, computed from a model developed by FERC, were used only in the PROSYM studies. FERC has been considered the appropriate source to provide these costs because of their expertise and their accessibility to all pertinent data. The process used to compute these "capacity" costs was defined in the DOE/FERC-0031, August 1979 report, Hydroelectric Power Evaluation. Essentially this process computes the annualized cost of constructing, operating, and maintaining a thermal powerplant and sending substation at a given Federal interest rate (6.875%). A transmission loss adjustment is also included. The data for the FERC model is updated periodically with information from various electric power industry sources to reflect the most recent powerplant construction costs, O&M costs, and current Federal interest rates. The annualized value used in this study is $86/kW-yr delivered to the distribution system. Note that this value assumes that the transmission links and receiving substations are already installed. This annual value does not include any adjustment for hydropower flexibility nor mechanical availability because these attributes of hydropower are accounted for in the ancillary service values and the outage assumptions used in the production cost models.

4.3.4 Combustion Turbine Costs and Technology. Because new capacity additions are comprised of natural gas-fired combined-cycle (CC) power plants, an effort was made to develop plausible and consistent assumptions regarding the evolution of the cost and performance of these plants over the study period.

A review done by the NPPC of planned and recently completed combined-cycle power plants concluded that a typical 250 MW class plant entering service in 1997 costs about $550/kW to construct. This cost is probably below market equilibrium level. The construction costs of large combined-cycle plants have declined up to 40 percent in recent years. Though much of this decline is attributable to improvements in engineering, manufacturing and construction, part results from a slow market for new generating capacity and excess manufacturing and construction capacity.

Current prices are therefore considered representative of low forecast conditions. The medium forecast base year capital cost is assumed to be about 10 percent higher than current prices. For the high forecast, base year capital cost is assumed to be 10 percent greater than Medium costs.

As discussed above the value used for construction costs in models for the medium case scenario was $601/kW-yr in 1998 dollars. This value best represents the current market conditions on the West Coast as researched by the NPPC. The Aurora and BPA model both include routines to identify future resource additions on an economic basis and the $601 value was used. For evaluation of Federal projects, the Corps of Engineers must estimate the construction costs based on the current Federal discount rate of 6.875%, and exclude taxes and insurance. To avoid distortion in future generation mixes, it was important that actual market conditions be used in this analysis, including market assumptions on taxes, discount rates, insurance, etc. The imposition of the artificial constraint of Federal financing to thermal plants could result in a completely unrealistic future resource mix. Hence, where benefits are to be based on Federal financial criteria, the approach used was to determine the likely with- and without-project scenarios using actual market financial criteria from the Aurora and BPA models, and convert the resulting costs to Federal financial criteria outside of the model. The Federal financing assumption was used in computing the fixed costs used in the PROSYM model.

Continuing advances in aerospace gas turbine applications are expected to lead to further reduction in the cost and increases in the efficiency of power generation equipment. For this study, cost reduction assumptions are based on projected improvement in gas turbine specific power.[3] Increases in specific power produce greater output with no increase in physical size, thereby reducing cost. Historical rates of improvement and estimated ultimately achievable rates of specific power suggest that over the study period specific power will continue to improve, on average, at constant rates. The resulting projections of annual cost reduction averaged - 0.6 percent in the Medium forecast, -1.2 percent in the Low and - 0.1 percent in the High forecast. These reductions were applied to both capital and operating costs of new CC plants.

State-of-the-art combined-cycle efficiency is closer to forecast ultimate efficiency than is specific power. Efficiency is therefore forecast to continue to improve, but at declining rates. Rates of efficiency improvement are based on alternative introduction dates of advanced turbine technologies, and decades by which ultimate turbine efficiency might be achieved. Using this approach, combined-cycle plant efficiencies would improve from 48 percent in 1997 to 54 percent by 2020 in the Medium forecast, to 57 percent in the Low and to 53 percent in the High forecast.[4]

4.3.5 Transmission Characteristics. Considerable transmission of electricity occurs between the regions of the WSCC. Several elements of this transmission had to be defined for the system power models to account for the shipment of electricity over the inter connections between regions. These included the transmission line capacity at different times of the year and day, losses in energy during transmission, and the transmission costs. The models consider all of these to determine the least costly way to meet load in a particular region. Figure 14 provides a graphical presentation of the transmission capabilities throughout the WSCC region. This figure shows the direct current (DC) and alternating current (AC) transmission capabilities from one region of WSCC to the other. Some of the capabilities are different depending on which direction the electricity is being sold and these are shown in the figure.

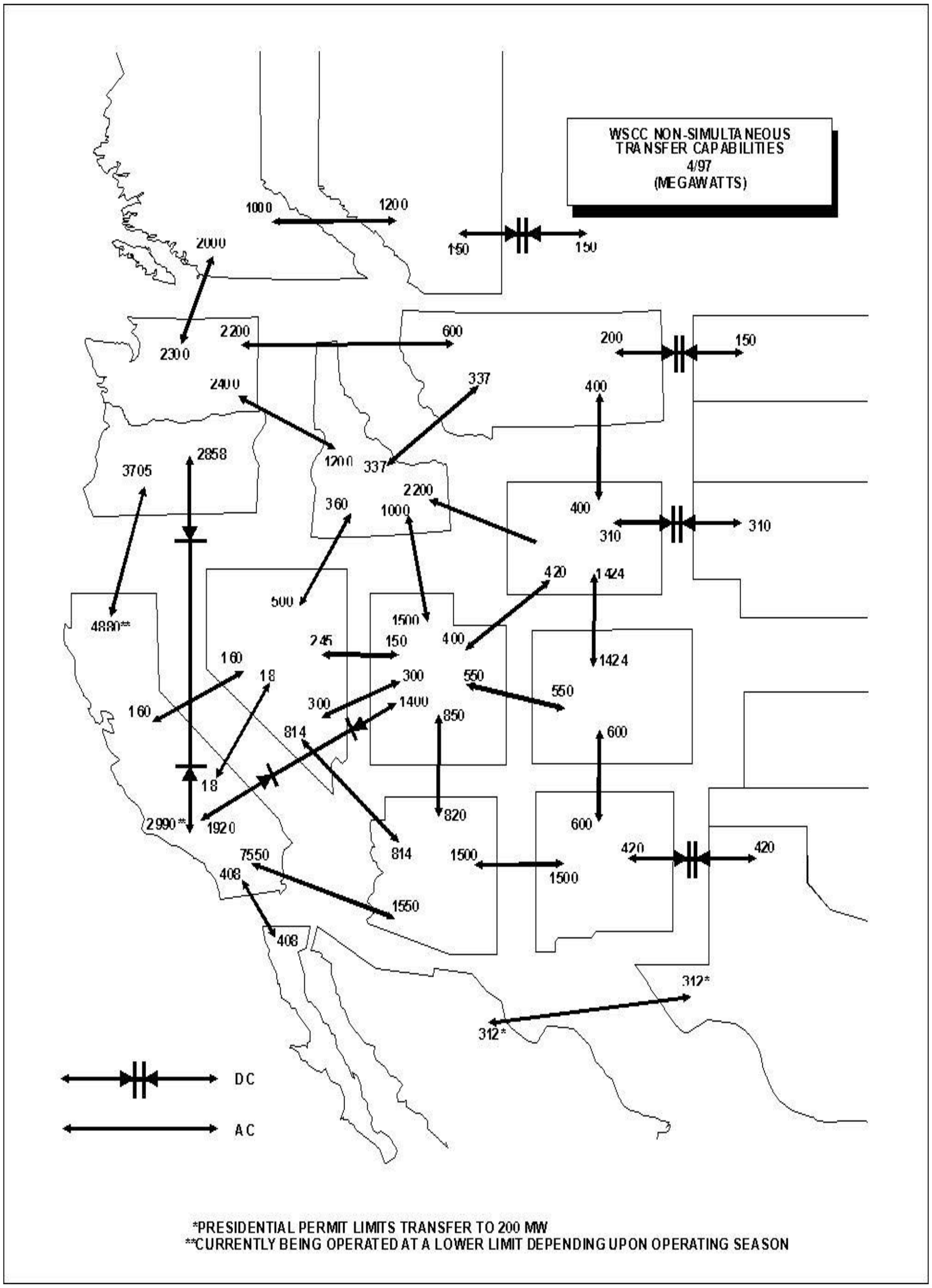


Figure 14: Transmission Capabilities in the WSCC

4.3.6 Unserved Load. In each of the three models, not all load was met in each time period. The amount of load to be met by the available resources is a fixed input to each of the models. The models then identify the most cost-effective way to meet that load given the resources available to the model. System simulations are run with the different water years, and the amount of available energy to serve load can vary substantially with the different water years. Since the models were trying to meet load in every hour, or block of hours, there were instances in which not enough energy or capacity was available to meet each hourly demand.

Different approaches were taken to account for the economic costs of the unserved load. In the real world, if shortages like this occur, the system will start shedding loads by not meeting certain loads, and curtailing the amount of energy provided in a particular time frame to some or all electric customers. There will clearly be an economic cost associated with this curtailment. One approach considered for this study was to simply assign a relatively high cost for every shortfall in satisfying the load. This high value was assumed to represent a proxy for the economic cost of curtailment. Another approach used was to recognize that demand-side management measures could be instituted to reduce peak load during these critical hours. This could include measures like remote control management of a household’s water heater, or interruption of an industrial customer’s production process. These measures would cost something to implement, and assigning costs to these measures was done on a somewhat judgmental basis. The costs would be step-wise increasing as the magnitude of unserved load increases. The following section describes the demand-side management approach that was included in the Aurora model, and also investigated in the BPA model.

4.3.7 Demand-Side Peaking Resources. This section describes the development of demand-side peaking measures that were available to meet the peak electricity demand periods in Aurora modeling.

The Aurora model included blocks of demand-side resources that were available to meet loads in any hour. The blocks are of increasing cost in $/MWh from 50 up to 1000. The amount of energy available from each block varies by region except for the highest cost block, which contains 50,000 megawatts of power in each region to avoid having too few resources in any condition.

There were several questions to answer for these blocks of demand-side peaking resources. First was how much total supply is reasonable up to the last block? (It was assumed that the last block represents the value of unserved energy rather than a demand side resource.) The second question was what would a supply curve of peak-reducing demand-side resources look like? What are reasonable block sizes and costs? Finally, what is the value of unserved energy in the last block?

One approach to the last question is to ask what the implicit value has been in the reliability criteria used in the regulated power system. The Energy Information Administration (EIA) addressed this question in its analysis of competitive electricity prices.[5] In their analysis, they stated that the reliability standard for electricity system design has been 1 day every 10 years of capacity shortage. Since the day could be covered by a simple-cycle combustion turbine at an annual carrying cost of about $36 per kilowatt, the cost, over about 2.4 hours a year (24 hours/10 years), would be about $15 per kilowatt-hour ($36/2.4 hours). EIA, however, interpreted the reliability rule to mean 10 hours of outage a year and calculated a value of $3.60 per kilowatt-hour for unserved energy. In their analysis they used $3.00 as a base amount but they did a sensitivity case at $6.00. Note that $3.00 per kilowatt-hour is the same as 3,000 mills per kilowatt-hour.

Regardless of whether you use 2.4 hours per year of outage or 10 hours per year of outage, our historical reliability criteria have placed a very high value on serving peak loads under nearly all conditions. Some utilities have recognized this fact and have attempted to put programs in place that are intended to reduce peak loads rather than pay for generation resources that are seldom used and, therefore, very expensive on a per kilowatt-hour basis.

Nevertheless, relatively little information has been found to quantify a supply curve for peak savings. EIA publishes data on utility energy and peak savings and costs, but the costs are not separated between peak saving and energy saving programs. In 1996, there were reported to be 5,134 megawatts of peak savings achieved in the WSCC. On a national basis the peak savings were a result of energy efficiency programs (48%), interruptible loads (25%), direct load control (19%), and other programs (9%). Four utilities accounted for 71% of the WSCC peak savings. The percent reduction in peak loads for these utilities were from 8% to 25% and averaged 11 %.

Although it is likely that the market will come up with more innovative approaches to reducing peak demands in response to time of use pricing, it was assumed that the market could achieve 26 percent as the maximum peak reduction through demand side voluntary actions. Table 14 below calculates the maximum peak savings for each Aurora region starting with the average annual demand for each region in the base year 1997. This was done in two steps based on ratios developed from projected WSCC data for 1997. Estimated peak demand is equal to average annual energy demand times the ratio of the peak month demand to average annual demand times the ratio of peak demand to average demand in the peak month. Table 14 shows the derivation of peak loads for Aurora regions in 1997.

Table 14
Derivation of Peak Lands

Step 1: Ratios From WSCC Regions

Region	Region Name	Average Annual Energy (GWh)	Peak Month	Peak Month Energy (MWa)	Ratio Peak Month to Avg Ann	Peak Demand (MW)	Peak/Energy Ratio for Peak Month
1	NWPP-US	232829	Jan	30016	1.129	39610	1.320
2	NWPP-CAN	102586	Dec	13070	1.116	17384	1.330
3	Rockies	45222	Jul	5445	1.055	7598	1.395
4	AZ-NM	77339	Aug	10500	1.189	15208	1.448
5	CA-SNV	261189	Aug	34743	1.165	51265	1.476

Step 2: Estimation of Peak Load for Aurora Regions

	Aurora Region	WSCC Region	Average Annual Energy (MWa)	Peak Month Estimate	Peak Load Estimate	26% of Peak Load	
	OR/WA	1	16779	18949	25006	6501	
	NCA	5	10730	12503	18449	4797	
	SCA	5	16783	19556	28856	7503	
	CAN	2	11842	13217	17579	4571	
	ID	3	2644	2789	3891	1012	
	MT	3	1554	1639	2287	595	
	WY	3	1455	1535	2141	557	
	CO	3	4681	4937	6890	1791	
	NM	4	2106	2505	3628	943	
	AZ	4	6474	7700	11152	2900	
	UT	3	2481	2617	3652	949	
	NV	5	2817	3282	4843	1259	

While Table 14 indicates a way of estimating the total amount of peak savings that might be feasible, the costs and steps in the supply curve are more difficult. By making some assumptions about cost allocations from the EIA data, a range of possible estimates of annual cost per kilowatt of peak savings could be developed. If half of the costs were assumed to be for peak savings, the costs for peak savings ranged from $6 per kilowatt per year to $40.

However, Aurora wants costs in mills per kilowatt-hour. The EIA data contains no information on the number of hours per year that peak savings are utilized, and that information is needed to calculate a mills per kilowatt-hour value. Assuming that half of the program costs were for peak load reductions, and that programs were applied for 50 hours a year, the four utility programs cost between 120 mills per kilowatt-hour and 800 mills per kilowatt-hour. The costs are very sensitive, however, to the two assumptions.

Another source of information is program evaluation results for load control programs that have been run by various utilities. A couple of these evaluations contained estimates of the number of hours that the programs were actually applied. The total annual hours of deferrals for various end-uses varied from 25 to 60 hours. The annual cost per kilowatt of peak reduction for these programs ranged from $19 to $33. The costs in mills per kilowatt-hour range from 320 to 1320.

While evidence from existing utility programs seems to indicate costs of peak reduction to be between 100 mills and 1300 mills, it is fair to assume that a competitive market with time of use pricing incentives and competing energy service providers would identify many less expensive opportunities for peak reductions. However, there is little evidence of the extent or cost of such savings. It is likely that existing programs reflect the implicit very high value put on reliability of power supply and delivery in a regulated market. The market has yet to explore what consumers would be willing to supply and what it might cost. The fact that consumers routinely undergo distribution and transmission related outages without any compensation might be an indication that the value of reliability is not as high as regulators have assumed. And the costs would be even less if consumers had some control over the duration and nature of the interruptions and could put substitute strategies in place ahead of time. In addition, if consumers chose to exercise peak reduction choices more frequently, the cost in mills per kilowatt-hour would be reduced significantly.

Considering all of this evidence and conjecture, the supply curve used in the Aurora model is presented in Table 15.

Table 15
Demand-Side Supply Curve

Step	Share of Potential	Mills/KWh
Step 1	First 20%	50
Step 2	Second 20%	100
Step 3	Third 20%	150
Step 4	Fourth 20%	250
Step 5	Last 20%	500
Step 6	Unserved Peak	1000

The shares of potential column in the middle of the table was applied to the "26 percent of peak load" column in Table 14 to determine the load available in each step of the supply curve.

4.4 MODELING OF AIR POLLUTANT EMISSIONS

This appendix does not provide information on air and water quality effects associated with the alternatives. The interested reader is referred to the Water Quality Appendix and the Air Quality Appendix. An air pollutant analysis done as part of this power study was provided to the authors of these other appendices for incorporation into their impact assessments.

This air pollutant portion of the power analysis was intended to identify, on a cursory level, increases or decreases in different types of emissions resulting from changes in the amount of hydropower production from the Lower Snake River. The Clean Air Act and concerns over greenhouse gasses are geared towards limiting emissions of pollutants into the air. One obvious advantage of hydropower generation is that it emits no pollutants into the air. With the reduction of hydropower production, alternative generation sources will be used to replace lost electricity. These alternatives will be thermal based and consequently will release increased levels of several harmful emissions.

The PROSYM power system model, which was used in this economic analysis, provided a convenient tool for identifying potential air pollutant emissions from thermal generating plants in the WSCC. The amount of hours the thermal power plants operate changes when the amount of PNW hydropower changes. Emission factors for each of the thermal plants were multiplied by the number of hours each plant operated to estimate pollutant releases. The emission results from the PROSYM model, with and without the hydropower changes, were compared to identify the changes in emissions. The particular emission factors used in this analysis were coordinated with the Environmental Protection Agency and were based on plant emission factors reported in standard EIA reports. The specific factors are presented in the Air Quality Appendix.

5.0 NET ECONOMIC EFFECTS BY ALTERNATIVE

5.1 EVALUATION APPROACH

As described in section 4.0 above, two different approaches were undertaken to estimate the net economic effects associated with changes in hydropower production in the PNW -- system production costs and market pricing.

The system production cost method identified the costs associated with meeting loads. The definition of system production cost in this analysis is the variable costs associated with the operation of existing and any new resources, plus the capital (fixed) costs associated with building new capacity. The criteria used to determine when new generating resources are needed and the cost of these resources is discussed in section 5.4 below. Changes in the total system production costs represent the net economic effects associated with each alternative.

The market pricing approach estimated the future market-clearing price based on estimates of the marginal costs for meeting loads. The Aurora model was used to identify the marginal cost to meet loads and these marginal costs were projected to be the market-clearing price. The net economic effects of each alternative were computed by multiplying the estimated market prices by the changes in hydropower generation from the base condition.

The economic effects due to hydropower will change over time based on changes in loads, resources and operating costs. The dates by which each of the alternatives can be expected to be built and in-service vary by plan. The information provided in this section is presented in various time frames. Many examples are presented for conditions projected to occur in year 2010. This year was chosen for demonstration purposes because it is a year in which all alternatives should be in-service. The assumed in-service date of each alternative is provided below. To present the results for each alternative in comparable terms, all prices are based on 1998 price levels. Future costs are all adjusted by appropriate discount rates to year 2005, and then annualized over a 100-year period of analysis. It is assumed that each alternative has a hundred-year life from the in-service date.

Alternative	**Assumed In-Service Year**
A2	2008
A3	2007
A5	2008
A6	2007
B1	2009
B2	2009
C1	2009
C2	2009

5.2 SYSTEM PRODUCTION COSTS ANALYSIS

The economic effects provided in this section are based on the system production costs as defined by the two production cost models. A range of results is presented based on three assumptions of the two key variables of fuel costs and loads. The future condition hereafter referred to as Low, combines the lowest estimate of fuel prices, the most rapid advancement in generation technology, and the low estimate of future load growth for all regions in the WSCC. Likewise, the Medium conditions combined the medium projections of fuel price, technology advancement, and load. The High condition combined the high projections of these three parameters. Specific explanation of the different projections is provided in section 4.3. Section 6.0, Risk and Uncertainty, provides additional treatment of the uncertainty associated with projections of future conditions.

Many of the tables in this section provide the description of total system production costs for each alternative as estimated by the BPA model and the PROSYM model. As can be seen from these tables, the BPA model was run over a much broader range of assumed conditions. This is a spreadsheet model, which has considerable flexibility. The PROSYM model is a much more complex hourly model, and time constraints did not allow for running this model for the full range of potential future conditions. Another major difference in the two models is that the BPA model was run for each of the 50 historic water years, while the PROSYM model was only run for an average water year based on the average of all 60 water years simulated by the HYSSR model. The scope of the BPA model is the PNW and California, while the PROSYM model includes all of the WSCC region.

The terminology used here refers to variable and fixed costs, and this is similar to the energy and capacity costs used in other studies. Energy is defined as that which is capable of doing work, and is measured over a time period. Electrical energy is usually measured in kilowatt-hours (kWh), megawatt-hours (MWh) or average MW (aMW - the average of megawatts per hour produced over the entire year of 8,760 hours). Capacity is the maximum amount of power that a generating plant can deliver, usually expressed in kilowatts or megawatts. In the total system production costs, the variable costs depend on the level of generation. They go up and down, as energy generation is varied to meet demand. The fixed costs are costs that do not vary with the level of electricity production. Fixed costs predominately represent the annualized value of constructing the new capacity.

5.2.1 Variable Production Costs. The two major components of the total system production costs are the variable production costs and the fixed (capital) costs. The fixed costs are presented in the following section. An output of both production cost models is the variable costs incurred by all generating facilities to meet the power loads. These variable costs include the fuel costs and the variable operating costs of the many different thermal plants. If energy is transmitted between market regions, the cost associated with this transmission is also included in the variable production costs. Table 16 provides a summary of the variable production costs by generating resources as estimated by the BPA model for one specific year (2010), the medium forecast condition, the average of 50 water years, and the two alternatives of A1 and A3. Table 17 provides the same type of information from the PROSYM model. These are provided as samples to demonstrate the nature of the estimated production costs for the PNW and California in the BPA model and the entire WSCC in the PROSYM model. Similar results were computed for all the future years of 2002 to 2017, for the low, medium, and high conditions, and for each of the 50 water years with the BPA model. Comparing the total variable production costs for year 2010 for alternatives A1 and A3 shows that with the A3 alternative the variable costs increase by $160 million and $202.6 million for the BPA and PROSYM models, respectively.

Table 16
System Production Costs Summary - Variable Costs
Year 2010, With HYDSIM & BPA Model, Medium Forecast

Type of Plant	aMW	Variable Costs (1998 $ Millions)	Average Var Costs (mills/kWh)
Variable Production Cost Summary With Alternative A1			
PNW Plants			
High Cost Coal	647	98.7	17.40
Low Cost Coal	2,414	207.0	9.79
Existing CT	55	11.2	23.26
Existing CC	1,594	214.7	15.37
New Region CC	5,135	609.4	13.55
Regional Firm Imports	1,477	120.0	9.27
Regional Hydropower	15,701	--	--
Curtailment/Demand Side	89	48.7	62.72
Total PNW	27,113	1,309.7	
PSW Plants			
Existing Resources	8,066	1,654.4	23.41
New Region CC	3,075	388.3	14.42
Curtailment/Demand-Side	103	50.9	56.21
Total PSW	11,244	2,093.7	
Transmission Costs		31.5	
Total Variable Costs		3,434.9	

Variable Production Cost Summary With Alternative A3			
PNW Plants			
High Cost Coal Low Cost Coal Existing CT Existing CC New Region CC Regional Firm Imports Regional Hydropower Curtailment/Demand Side	659 2,436 53 1,658 6,063 1,480 14,477 78	100.4 208.8 10.8 223.4 722.9 120.3 -- 42.9	17.40 9.79 23.26 15.37 13.61 9.27 -- 63.10
Total PNW	26,904	1,429.5	
PSW Plants			
Existing Resources New Region CC Curtailment/Demand- Side	8,249 3,094 111	1,692.6 390.7 54.9	23.42 14.42 56.52
Total PSW	11,454	2,138.27	
Transmission Costs		27.5	
Total Variable Costs		3,595.3	

Differences From A1 (A3-A1)			
PNW Plants			
Must Run[1]	--	--	
High Cost Coal	12	2	
Low Cost Coal	21	2	
Existing CT	(2)	(0)	
Existing CC	64	9	
New Region CC	928	114	
Regional Firm Imports	3	0	
Regional Hydropower	(1,225)	--	
Curtailment/Demand Side	(11)	(6)	
Total PNW	(209)	120	
PSW Plants			
Must Run[1]	--	--	
Existing Resources	183	38	
New Region CC	19	2	
Curtailment/Demand-Side	7	4	
Total PSW	209	45	
Transmission Costs		(4)	
Total Variable Costs		160.4	

[1]The must run thermals, primarily nuclear plants, are not included because generation does not vary between alternatives.

Table 17
PROSYM Production Costs (Variable Cost Summary), Total WSCC Supply Area
Average Water Year, Medium Forecast ($'98 Millions) Year 2010

Generation Resource	A1 Base Case		A3 890 MW Replacement		Difference A3-A1	
	Energy (MWh)	Variable Cost	Energy (MWh)	Variable Cost	Energy (MWh)	Variable Cost
NG NCal	19,407,900	$737.0	19,316,200	$734.7	(91,700)	$(2.32)
PG&E IPPs	19,950,400	616.7	19,896,900	614.7	(53,500)	(1.93)
Nuclear	47,815,500	1,772.1	48,174,700	1,777.1	359,200	4.96
Geothermal	9,897,300	592.8	9,913,200	593.3	15,900	0.50
FO #2	1,168,000	151.6	1,245,200	160.9	77,200	9.37
Inter LD	4,000	67.6	4,300	67.7	300	0.14
Wind	376,500	12.3	379,100	12.4	2,600	0.08
Future CC	202,505,500	5,346.0	209,601,600	5,483.7	7,096,100	137.70
NG SCal	21,193,600	1,131.0	21,171,300	1,128.1	(22,300)	(2.93)
SDG&E IPPs	1,392,300	53.4	1,393,000	53.4	700	0.01
Jet Fuel	200	0.2	200	0.2	--	(0.01)
NG AZ/NM	8,930,700	395.1	8,897,300	392.7	(33,400)	(2.40)
SCE IPPs	26,247,300	926.7	26,248,300	926.3	1,000	(0.38)
NG BC	681,900	21.6	619,100	19.6	(62,800)	(2.03)
FO #6	240,300	42.7	210,200	39.8	(30,100)	(2.88)
NG PNW	16,085,200	464.1	17,103,800	494.0	1,018,600	29.86
Coal NW	11,033,100	274.6	11,508,700	282.9	475,600	8.33
Other	3,160,400	102.0	3,226,000	104.0	65,600	2.02
Wood	1,833,200	67.2	1,873,100	68.6	39,900	1.36
Coal AZ/NM	73,678,000	2,053.9	73,666,200	2,053.9	(11,800)	(0.05)
NG RM	4,986,900	158.0	5,169,600	164.2	182,700	6.15
Coal RM	113,105,300	2,323.9	113,468,500	2,328.0	363,200	4.11
Sun	1,600	0.2	1,600	0.2	--	--
NG Alberta	3,575,300	105.2	3,638,900	106.5	63,600	1.34
Coal Canada	42,301,200	387.6	42,442,900	388.3	141,700	0.78
NG RM-Col	3,171,200	122.4	3,184,300	122.8	13,100	0.39
Biomass	40,200	1.3	40,200	1.3	--	--
Waste Heat	257,000	8.6	257,000	8.6	--	--
Pump Storage	2,093,300	5.4	2,097,200	5.4	3,900	0.02
Hydro	285,399,900	--	274,993,800	--	(10,406,100)	--
Transaction	1,171,500	57.5	1,171,500	57.5	--	--
Net Totals	**921,704,700**	**$17,998.5**	**920,913,900**	**$18,190.6**	**(790,800)**	**$192.16**
Wheeling Cost		$200.9		$195.8		$5.18
Unserved Energy	8,000	$1.2	8,000	$1.2	--	--
Energy Adjustment**		--	790,800	$15.6		--
Total	**921,712,700**	**$18,200.5**	**921,712,700**	**$18,403.2**	**--**	**$202.61**

**Note: The difference in total energy between alternatives should be zero because both alternatives are serving the same load. Although a difference is shown here, it represents less than 1/10th of 1 percent of total system energy. The energy adjustment was made based on average production cost per GWh.

The results of the BPA model as shown in Table 16 are provided by resource type in the PNW. Some thermal plants in the PNW are classified as must run thermal which must be run due to the nature of the plant (*i.e.*, nuclear) or long term contracts which require a constant level of production except during routine re-fueling and scheduled maintenance periods. The generation from these plants will not vary with the different alternatives, so the variable costs are not included in the table. The generation and variable costs from PSW resources are presented in total in this table. The amount of generation from new CC plants is shown for alternatives A1 and A3. However, more new CC plants were assumed to be constructed with A3 to replace some of the lost hydropower generation and capacity. The costs associated with transmitting energy between regions are also reported in this table.

One point of importance is how the loss in hydropower with A3 (and other alternatives) is accounted for in these models. From Table 16 it can be seen that the HYDROSIM model estimated that with alternative A3 that the amount of hydropower production was less than with A1 by 1,225 average MW. This difference in hydropower generation was made up by a combination of thermal alternatives (primarily natural gas-fired combined-cycle combustion turbines) at a higher cost. It is these higher variable costs that made up the increased production costs, and a large component of the net economic effects.

Table 16 demonstrates that with the breaching of the four Lower Snake River dams and the building of additional CC plants in the PNW, the total generation in the PNW in year 2010 will be 209 aMW less than in the base condition. At the same time, the generation in the PSW will increase by 209 aMW to meet the 2010 loads in the PNW and PSW regions. So, on an annual basis, the PNW will import an additional 209 aMW from the PSW in 2010 with alternative A3.

The variable costs for hydropower generation in both power production cost models are shown as zero for all alternatives. This is because there is no cost of fuel for hydropower. It is recognized that there will be some differences in fixed O&M and capital costs for hydropower between the different alternatives, but these are not included in this hydropower analysis. The implementation costs analysis does include the differences in hydropower O&M and capital costs with all alternatives and including them in this hydropower analysis would have resulted in double-counting this impact. The interested reader is referred to the Implementation Cost section of the Economic and Social Appendix.

The system variable production costs shown in Table 17 from the PROSYM model is the combination from each of the 14 transmission areas within the WSCC. These costs include the costs of operating the thermal plants, which consists of the variable O&M costs and the fuel costs. This table shows that for year 2010 the system variable production costs would be $202.6 million higher with the removal of the Lower Snake dams. This is computed by adding these costs for each hour of the simulated year. Also included in the production costs of each region are the transmission costs associated with any imports of energy into the region. The import of energy is reduced to account for the loss in energy due to in transmission resistance. For example, if 100 MWh is generated in one region and this is imported into another region, less than 100 MWh will be delivered to the importing region. In this example, the production costs of variable O&M and fuel for generating the 100 MWh will be reported in the region it was generated. The importing region will receive less than 100 MWh (less transmission losses) and the model will add the transmission costs to the production costs.

To demonstrate the impacts to different transmission areas, Table 18 provides the PROSYM results for alternatives A1and A3 by the 14 different areas. These results are for the year of 2010, with the medium forecast projections, and the average of all water year simulations for hydropower production in the PNW. The production costs in Table 18 are slightly different than Table 17 because of the energy adjustments and other minor differences in summing over transmission areas. As can be seen in Table 18 the vast majority of differences in system variable production costs with the removal of the Lower Snake River dams occurs in the Pacific Northwest.

Table 18
PROSYM Production Cost Summary by Area
Year 2010 Conditions - Average of Water Years
Medium Forecast Conditions - 1998 $ Million

Transmission Area	Alternative A1	Alternative A3	Alternative A3 - A1
	Total Area Production Costs	Total Area Production Costs	Total Area Production Costs
Alberta	$693.8	$698.7	$4.9
Arizona	1,977.0	1,977.1	0.1
BC Hydro	270.8	269.4	(1.4)
Comision Federal de Electricidad	681.0	674.8	(6.2)
Colorado/Wyoming	1,053.8	1,054.1	0.3
El Paso	97.2	97.1	(0.1)
Imperial Irrigation	51.3	51.3	(0.0)
Inland Northwest	543.7	553.3	9.6
Los Angeles Dept. of Water & Power	526.2	523.8	(2.4)
Montana	337.0	342.3	5.3
Northern California	3,266.9	3,272.3	5.4
Pacific Northwest	1,175.1	1,348.9	173.8
Palo Verde	978.3	978.2	(0.1)
Public Service of New Mexico	825.7	826.1	0.4
Southern California Edison	2,825.6	2,825.6	0.0
San Diego Gas & Electric	750.2	750.0	(0.2)
Southern Nevada	897.6	897.3	(0.3)
Utah	731.5	734.2	2.7
Wyoming	262.0	262.4	0.4
Total[1]	**$17,944.7**	**$18,136.9**	**$192.2**

[1]Results do not include adjustments made in Table 17 for wheeling costs, energy adjustments, and other minor transaction adjustments.

5.2.2 Fixed Production Costs. The previous section presented the costs associated with meeting energy demands, or the variable costs. This section and section 5.4 discuss the capacity costs, or the fixed costs. For either of the production cost models to meet the loads projected over time, new generating facilities will need to be constructed. With each alternative, a different mix of new generating facilities will be needed to account for the varying amounts of hydropower production. The decision of when and how much new capacity is to be built is an important element of the analysis. The decision process used to determine how much new capacity is needed is provided in section 5.4 below.

Each of the two production cost models treats new thermal capacity in a different manner. The BPA model includes an optimization element that determines how much new capacity will be built based on the economic return from building the capacity. This is explained in detail below. The fixed costs of new capacity and the variable costs are both developed within the BPA model and these are summarized in the next section. The PROSYM model does not include these capacity costs and they must be added to the variable costs to define total production costs.

5.2.3 Total System Production Costs. Table 19 summarizes the total system production costs compared to A1 from the two models for year 2010, the medium projection condition, and the average over all water years. The total system production costs include the variable costs of operating all the resources in year 2010 (column 2) and the fixed costs (column 4) associated with the additions of new resources that are needed to meet the projected load in that year. The variable costs in any given year include the operating costs for the resources added that year, and all resources in place in that year including new resources built prior to that date. The fixed costs are the annualized capital costs of new capacity. For example, with the BPA model and the A3 alternative, 820 average MW of new capacity was added up to year 2010 over the base condition. The annual fixed cost of this additional capacity was $88 million. The total system production costs in 2010 for A3 were the combination of the variable costs of $160 million and the fixed costs of $88 million.

Table 19
Total System Production Cost Summary
Year 2010 Simulation - Medium Forecast Conditions
Costs Compared to Alternative A1

Alternative	Variable Production Costs (1998 $ Million)	Additional CC Capacity[1] (aMW)	Additional Annual Fixed Costs (1998 $ Million)	Total System Production Costs (1998 $ Million)
Hydrosim and BPA Models				
A2	$(0)	(80)	$(8)	$(8)
A3	160	820	88	248
A5	169	690	75	244
A6a	(16)	(30)	(4)	(20)
A6b	(4)	30	3	(1)
B1	314	1,610	173	487
B2				
C1	235	1,270	136	371
C2				
HYSSR and PROSYM Models				
A2				
A3	$203	820	$77	$280
A5				
A6a				
A6b				
B1				
B2				
C1				
C2				

[1]Includes all capacity additions up to and including this year. This is average MW.
To determine total new capacity, divide by the availability factor of 92%.
For example, for A3, the new capacity up to and including 2010 is 890 MW (820/.92).

Table 20 presents the system production costs on a year-by-year basis for the medium projection condition. This table also provides the total present worth values for each alternative and the average annual costs based on the three different discount rates. Table 21 provides the average annual production cost for each alternative in the low, medium, and high projection conditions. The results in these two tables show that the net present values of the stream of costs over time vary significantly with the different discount rates. But the average annual equivalents at the different discount rates are very close over all three discount rates. The net economic effects measured as the average annual system production costs for alternative A3 vary from $255 to $260 million with the medium forecast conditions and the different discount rates. However, the different forecast conditions have substantial impacts. For example, with the 6.875 % discount rate, the system production costs as measured from the base condition range from $187 to $339 million for alternative A3.

Table 20
Total System Production Costs Over Time
Differences From Alternative A1
1998 Real Million Dollars, Starting at In-Service Date
Medium Production Cost Assumptions

Year	A2	A3	A5	A6a	A6b	B1	B2	C1	C2
HYDROSIM and BPA Model									
2005	$0	$0	$0	$0	$0	$0		$0	
2006	0	0	0	0	0	0		0	
2007	0	242	238	(20)	(1)	0		0	
2008	($8)	244	240	(20)	(1)	0		0	
2009	($8)	246	242	(20)	(1)	484		369	
2010	($8)	248	244	(20)	(1)	487		371	
2011	($8)	249	245	(21)	(1)	490		374	
2012	($9)	251	247	(21)	(1)	494		377	
2013	($9)	253	249	(21)	(1)	497		379	
2014	($9)	254	251	(21)	(1)	500		382	
2015	($9)	257	253	(21)	(1)	504		385	
2016	($9)	259	255	(21)	(1)	508		388	
2017	($9)	261	257	(22)	(1)	511		391	
2018	($9)	261	257	(22)	(1)	511		391	
2019 - 2104	($9)	261	257	(22)	(1)	511		391	
Results									
NPV at 0%	($936)	$25,963	$25,594	($2,167)	($98)		$39,024		
NPV at 4.75%	(191)	5,347	5,268	(444)	(22)		8,069		
NPV at 6.875%	(132)	3,705	3,650	(307)	(16)		5,600		
Avg Annual at 0%	(9)	260	256	(22)	(1)		390		
Avg Annual at 4.75%	(9)	256	253	(21)	(1)		387		
Avg Annual at 6.875%	(9)	255	251	(21)	(1)		386		

HYSSR and PROSYM									
2005		$0							
2006		0							
2007		239							
2008		253							
2009		266							
2010		280							
2011		283							
2012		286							
2013		289							
2014		291							
2015		294							
2016		297							
2017		300							
2018		300							
2019 - 2104		300							
Results									
NPV at 0%		$29,779							
NPV at 4.75%		5,526							
NPV at 6.875%		3,658							
Avg Annual at 0%		298							
Avg Annual at 4.75%		26							
Avg Annual at 6.875%		252							

Table 21
Average Annual Total System Production Costs
Results From Two Different Models
1998 Real Million Dollars, Various In-Service Dates, 100-Year Analysis
All Amounts are Cost Differences From Alternative A1

Production Costs				Production Costs	
HYDSIM and BPA Model				HYSSR and PROSYM	
Alternative	**Low**	**Med**	**High**	**Alternative**	**Med**
Average Annual Costs at Discount Rate 6.875%					
A2	($6)	($9)	($12)	A2	
A3	187	255	329	A3	$252
A5	184	251	307	A5	
A6a	(19)	(21)	(31)	A6a	
A6b	(2)	(1)	(6)	A6b	
B1	379	504	635	B1	
B2				B2	
C1	283	386	480	C1	
C2				C2	
Average Annual Costs at Discount Rate 4.75%					
A2	($6)	($9)	($12)	A2	
A3	187	256	332	A3	$265
A5	184	253	310	A5	
A6a	(19)	(21)	(31)	A6a	
A6b	(2)	(1)	(6)	A6b	
B1	380	506	640	B1	
B2				B2	
C1	283	387	484	C1	
C2				C2	
Average Annual Costs at Discount Rate 0%					
A2	($6)	($9)	($13)	A2	
A3	186	260	339	A3	$298
A5	184	256	316	A5	
A6a	(19)	(22)	(32)	A6a	
A6b	(2)	(1)	(6)	A6b	
B1	380	510	650	B1	
B2				B2	
C1	284	390	492	C1	
C2				C2	

The comparison of the BPA and PROSYM production cost models can be made with results shown in Tables 19 and 20. The differences for A3 and A1 of the total system production costs estimated with the BPA model ($248 million) and the PROSYM model ($280 million) for year 2010 shows that the PROSYM model estimates higher impacts by about 13 percent. This was expected because of the basic characteristics of PROSYM and the slightly different modeling approach. For example, PROSYM did not include demand-side resources. PROSYM allowed the hydropower generation to be dispatched in an optimum manner that does not fully reflect all of the existing constraints placed on hydropower units. Since PROSYM is an hourly model it captured those hours of the year in which the highest cost resources would be dispatched to meet peak demand, and the BPA model may not account for these extreme peaks. Because PROSYM is a very complex model to operate, and the results were similar to the BPA model, it was not run for all study alternatives. PROSYM modeling was limited to the medium forecast conditions and average water year. Consequently, many of the tables in this report do not include PROSYM results for all scenarios. However, the study team considered the PROSYM results to be a valuable crosscheck of the other modeling results and it was a useful tool to test many elements of this study.

5.3 MARKET PRICE ANALYSIS

The model results presented in the previous section provide the total production costs associated with meeting load. This was based on dispatching resources from the lowest cost to higher cost resources until load in each time frame was met. The variable cost of the last resource dispatched to meet the load in that time frame is defined as the marginal cost for that period. In a fully competitive market, this marginal cost will equal the market price for which all the electricity will be sold. In this type of competitive market, the market price represents society's willingness-to-pay. Hence, defining the economic effects based on the market-clearing price is an equivalent approach to the net economic values that are being estimated for other uses of the Snake River, such as navigation and recreation.

The Water Resources Council's Principles and Guidelines recognized the universally accepted economic concept that society is best served in making its resource allocation decisions by pricing output equal to marginal costs. Marginal costs can be characterized as being either short-run or long-run. In the short-run, plants are fixed; consequently, the marginal cost will reflect current changes in variable costs. In the long run, plant capacity and the attending fuel mix can be adjusted to minimize the total costs of producing new outputs. This not only affects future variable costs, but also future capacity additions to the extent they can be postponed or avoided.[6]

The electric industry is moving towards a more competitive market, but is currently in a transition period which mixes wholesale pricing at marginal costs with most retail pricing based on average costs, and established contracts that may or not reflect either of these approaches. For these reasons, this report provides results from the two approaches of system production costs and the market.

This section presents the results of a market-clearing price approach, based on the results of studies done by the NPPC using the Aurora model. The NPPC results were developed using the market-clearing price approach, and these are reported in the NPPC report, *Analysis of the Bonneville Power Administration's Potential Future Costs and Revenues, 5 June, 1998*, attached as Technical Exhibit B.

To evaluate each of the alternatives, the market prices from Aurora, as defined by the marginal costs, are applied to the difference in PNW hydropower generation from the base condition (A1). Since the marginal cost varies by transmission area and by time periods, the study team had to select which market prices would be most appropriate to evaluate impacts. The study team chose to multiply changes in PNW hydropower generation by the Aurora market price developed for the states of Oregon and Washington. This price most accurately reflects the value of PNW energy.

The marginal costs vary by hour, by day, and by month. To simplify the analysis hourly prices were allocated to peak and off-peak periods and averaged for each month to obtain estimates of peak and off-peak prices. Table 22 provides the monthly on-peak and off-peak market price defined by Aurora, for the medium projection condition, for the two specific years of 2005 and 2010, in nominal prices and real 1998 dollars.

Table 22
Average Market-Clearing Prices From NPPC Study
Medium Projection Condition For Two Years
(mills/kWh)

Month	On-Peak Nominal	Off-Peak Nominal	On-Peak 1998 $	Off-Peak 1998 $
Year 2005				
Sep	42.39	31.55	35.66	26.54
Oct	32.32	28.60	27.19	24.06
Nov	33.78	28.14	28.42	23.68
Dec	37.58	32.81	31.62	27.60
Jan	36.87	32.46	31.02	27.30
Feb	34.63	29.97	29.13	25.21
Mar	26.77	26.35	22.52	22.17
Apr	25.95	20.02	21.83	16.84
May	20.05	18.17	16.87	15.29
Jun	24.37	17.59	20.50	14.80
Jul	32.10	25.32	27.00	21.30
Aug	43.39	31.32	36.50	26.35
Avg	32.52	26.86	27.36	22.60

Year 2010				
Sep	54.40	32.79	40.45	24.38
Oct	32.89	29.29	24.45	21.78
Nov	36.13	31.01	26.87	23.06
Dec	39.13	32.77	29.09	24.37
Jan	37.78	35.20	28.09	26.18
Feb	38.83	31.05	28.88	23.09
Mar	36.58	27.14	27.20	20.18
Apr	31.01	20.16	23.06	14.99
May	18.81	18.44	13.99	13.71
Jun	22.05	17.56	16.40	13.06
Jul	27.06	27.61	20.12	20.53
Aug	41.35	39.91	30.74	29.67
Avg	34.67	28.58	25.78	21.25

The average monthly prices for peak and off-peak were used to identify the economic effects associated with changes in hydropower generation. This was done by computing the change in hydropower generation from the current conditions, by subtracting the PNW hydropower generation with each alternative from the base condition (alternative A1). Adjustments were also made to the monthly hydropower generation by separating it into peak and non-peak hours based on the historic distribution shaping of the monthly hydropower generation. Table 6 presented the hydropower generation changes for each alternative based on average monthly generation. The values in Table 23 were computed by multiplying the projected market price (from Table 22) by the changes in hydropower output from the base condition using both HYSSR and HYDROSIM outputs. This table labels the economic effects as net economic costs to represent changes from the base condition. For alternatives A2, A6a and A6b the net economic costs are shown as negative numbers. This means that there will actually be economic benefits compared to the base condition because more hydropower is generated with these alternatives. The net economic costs are only presented for the periods from the date of in-service for each alternative. It was assumed that alternative A1 (the base condition) would occur up to the in-service date, hence the net economic costs are zero from the present to the years of 2007 to 2009. Market prices were estimated for all the years from the present to 2017, the end of the future projection period.

Table 23
Net Economic Costs Computed From Market Prices
(Market Clearing Price Multiplied By Change In Hydropower
Differences From Alternative A1
1998 Real Million Dollars, Starting At In-Service Date
Medium Condition Projections

Year	A2	A3	A5	A6a	A6b	B1	B2	C1	C2
HYDROSIM									
2005	$0	$0	$0	$0	$0	$0		$0	
2006	0	0	0	0	0	0		0	
2007	0	237	223	(19)	0	0		0	
2008	(8)	227	209	(18)	(0)	0		0	
2009	(8)	226	210	(14)	(0)	445		339	
2010	(7)	223	207	(14)	(0)	443		335	
2011	(7)	231	217	(15)	0	458		347	
2012	(7)	226	212	(18)	0	448		339	
2013	(7)	223	207	(17)	(0)	443		335	
2014	(7)	222	204	(16)	(1)	443		335	
2015	(7)	218	198	(14)	(1)	436		329	
2016	(7)	222	205	(13)	(0)	442		334	
2017	(7)	216	198	(17)	(0)	432		326	
2018	(7)	216	198	(17)	(0)	432		326	
2019 - 2104	(7)	216	198	(17)	(0)	432		326	
Results									
NPV at 0%	($698)	$21,719	$19,933	($1,709)	($31)	$43,324		$32,700	
NPV at 4.75%	(148)	4,586	4,224	(347)	(5)	9,098		6,871	
NPV at 6.875%	(104)	3,213	2,964	(240)	(4)	6,359		4,803	
Avg Annual at 0%	(7)	217	199	(17)	(0)	433		327	
Avg Annual at 4.75%	(7)	220	203	(17)	(0)	436		330	
Avg Annual at 6.875%	(7)	221	204	(17)	(0)	438		331	

HYSSR										
2002	$0	$0	$0	$0	$0	$0	$0	$0	$0
2003	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0
2007	0	228	215	(21)	(2)	0	0	0	0
2008	(10)	235	224	(20)	(3)	0	0	0	0
2009	(10)	230	219	(20)	(3)	447	422	336	309
2010	(10)	227	215	(21)	(3)	442	408	332	296
2011	(10)	227	213	(22)	(2)	442	405	332	294
2012	(10)	223	207	(21)	(3)	435	396	326	287
2013	(10)	226	213	(20)	(3)	440	412	330	300
2014	(9)	220	207	(20)	(3)	430	398	323	290
2015	(9)	220	207	(19)	(3)	420	398	323	290
2016	(9)	220	207	(21)	(2)	410	398	323	290
2017	(9)	220	207	(21)	(3)	400	398	323	290
2018	(9)	220	207	(21)	(3)	390	398	323	290
2019 - 2104	(9)	220	207	(21)	(3)	430	398	323	290
Results									
NPV at 0%	($943)	$22,109	$20,761	($2,056)	($297)	$43,044	$39,956	$32,360	$29,053
NPV at 4.75%	(199)	4,672	4,396	(428)	(60)	9,007	8,402	6,804	6,114
NPV at 6.875%	(140)	3,274	3,083	(298)	(41)	6,292	5,877	4,758	4,278
Avg Annual at 0%	(9)	221	208	(21)	(3)	430	400	324	291
Avg Annual at 4.75%	(10)	224	211	(21)	(3)	432	403	326	293
Avg Annual at 6.875%	(10)	225	212	(21)	(3)	433	405	328	294

Table 24 provides the average annual net economic costs based on the market price analysis, by different discount rates, by the two hydro-regulation models, and for the high, medium, and low economic forecast conditions. The values in this table were based on the differences from the base condition (A1). The results from the different hydro-regulation models of HYDROSIM and HYSSR are not significantly different.

Table 24
Average Annual Net Economic Costs From Market Prices
1998 Real Million Dollars, Various In- Service Dates, 100-Year Analysis
All Amounts Are Cost Differences From Alternative A1

HYDROSIM and Aurora Prices				HYSSR and Aurora Prices			
Alternative	**Low**	**Med**	**High**	**Alternative**	**Low**	**Med**	**High**
Average Annual Costs At Discount Rate 6.875%							
A2	($5)	($7)	($12)	A2	($7)	($10)	($16)
A3	151	221	347	A3	154	225	353
A5	140	204	328	A5	146	212	338
A6a	(10)	(17)	(27)	A6a	(14)	(21)	(30)
A6b	0	(0)	1	A6b	(2)	(3)	(5)
B1	291	438	687	B1	289	433	680
B2				B2	275	405	652
C1	221	331	521	C1	219	328	516
C2				C2	202	294	482
Average Annual Costs At Discount Rate 4.75%							
A2	($5)	($7)	($12)	A2	($7)	($10)	($16)
A3	148	220	347	A3	151	224	353
A5	138	203	327	A5	143	211	337
A6a	(10)	(17)	(27)	A6a	(13)	(21)	(30)
A6b	0	(0)	1	A6b	(2)	(3)	(5)
B1	287	436	687	B1	285	432	680
B2				B2	271	403	651
C1	217	330	520	C1	216	326	515
C2				C2	199	293	480
Average Annual Costs At Discount Rate 0%							
A2	($5)	($7)	($12)	A2	($6)	($9)	($16)
A3	141	217	346	A3	143	221	353
A5	132	199	325	A5	136	208	336
A6a	(10)	(17)	(27)	A6a	(13)	(21)	(30)
A6b	0	(0)	1	A6b	(2)	(3)	(5)
B1	277	433	685	B1	289	430	682
B2				B2	276	400	647
C1	210	327	519	C1	208	324	514
C2				C2	193	291	477

5.4 RELIABILITY AND CAPACITY EFFECTS

This section describes how the changes in the hydropower capacity in the PNW were investigated. Of particular interest is how will hydropower capacity reductions impact the generation reliability in the region and the WSCC in total, and to what extent additional thermal capacity will be built to replace losses in hydropower capacity.

To simplify the approach the reliability of the system is broken into two components for this examination: generation reliability and transmission reliability. This section concentrates on the reliability of the generation capacity of the system. Section 5.5 below will address the impacts that different alternatives will have on transmission reliability. It was assumed here that transmission reliability will not be allowed to change from existing conditions for any of the alternatives, and the costs of maintaining this transmission reliability are presented in section 5.5.

5.4.1 Conceptual Considerations. Generation reliability can be evaluated numerous ways, but all approaches are generally based on how well the available generating resources can meet load in all time periods. In the PNW the generation reliability of the power system primarily depends on the availability of water to generate hydropower. In other systems throughout the nation, in which hydropower is a very small component of the total resource mix, planned and forced outages of thermal plants are important determining factors for reliability. So, to determine the generation reliability in this study the probable range of hydraulic conditions must be examined and this was done with the two system hydro-regulation models, HYSSR and HYDROSIM.

The scheduled and unscheduled (forced) outages of resources are also a significant component of any generation reliability analysis. The system power models used in the analysis account for the forced outages by either including random outages or de-rating the units. For example, the BPA model de-rates the new CC units by 5 percent to account for the probability of unscheduled outages and an additional 3 percent for the scheduled maintenance. The PROSYM model incorporates forced and maintenance outages on a plant by plant basis based on outages common to the different type of resources.

Traditionally, the PNW generation reliability has been defined considering the dependable capacity of the hydropower system based on critical water conditions and high demand periods. This type of "firm planning" analysis has taken several forms over the years, all of which were geared towards assuring that loads are met with available generation with a high level of probability. PNW hydropower dependable capacity has been defined in different ways in past studies. For example, the dependable capacity has been based on severe water conditions associated with the historic water conditions of the 42 month interval from September 1928 through February 1932, the hydropower capability with January 1937 water, sustainable capacity over 50 hours per week based on January 1937 water and load conditions, and instantaneous capacity with different water conditions. Under these traditional approaches, if study alternatives reduced the hydropower dependable capacity, it was assumed new capacity would be built to replace the exact amount of lost dependable capacity. This approach has not been taken in this analysis, but it is discussed in Section 5.4.4 below to examine how the study results could change with a more traditional study approach.

As with other issues addressed in this report, the movement to a competitive electricity market affects how to analyze the issue of reliability and replacement capacity. With less regulation of the electrical industry and more independent power producers, many experts feel that market conditions will be the driving force to determine when new resources will be built. The expectation is that, in a competitive market, the decision to build new resources will be based on economic return rather than some regulatory convention. This assumption provided the conceptual basis for the reliability and replacement capacity portion of this report.

On a simplified basis the market driven capacity addition decisions will probably be based on the following considerations. The market-clearing price for any selected time period will generally be based on the marginal costs of the last resource. Only during periods of extremely high demand (peak demand), typically on very hot summer (or cold winter) days, when the demand for electricity approaches the available generating capacity, would prices rise above the marginal costs of the most expensive generator operating. Because the amount of capacity available at any point in time is fixed, and new generating capacity cannot be built quickly, the only way in which demand and supply could be kept in balance during extremely high demand periods would be through an increase in the price, to a level that would encourage some consumers to reduce their usage. The frequency of these periods of high prices will help determine whether new generating resources will be built. The price adjustment during periods of peak demand can be thought of as representing the value consumers place on reliability.

In conditions where demand approaches the limits of capacity and market-clearing prices are above marginal operating costs, power producers can collect high premiums. As capacity becomes scarce this situation would occur more frequently and increase the incentive for investors to provide new generating capacity. When the new capacity is available for service, shortages would be relieved, and the frequency of extremely high peak prices will fall.

This price signaling concept and the frequency of occurrence formed the decision criteria for construction of new resources in the BPA and Aurora models used in this power analysis. With these models new resources are assumed to be built when the marginal costs are sufficiently high and frequent to cover the cost of constructing the resource (in terms of the annualized fixed costs) and the variable operating costs.

The BPA model, for example, first simulates each year without any new resources being added in that year. The model then tests to see if it is economically justified to add new resources. To be justified a new power unit must produce enough energy in that year at the marginal costs to equal or exceed the annual fixed and variable costs of the new resource. If the resource is economically justified it is added to resource mix and the model continues this process until an optimized amount of new resources is identified.

This economic justification approach was used in this study to estimate how many new resources would be built in each of the study alternatives, on a year-by-year basis from the present to year 2017. The additional fixed costs are included as a component of the total system production cost for identifying the net economic effects of each alternative. These costs are similar to the traditional capacity costs identified in past studies.

Several important elements of this generation reliability approach had to be considered by the study team. Of most interest in this analysis was, (1) the treatment of periods in which existing resources were insufficient to meet electricity load, (2) consideration of system reserves requirements and dependable capacity, and (3) the type and price of new resources. These points are discussed in the following sections along with the sensitivity analysis undertaken to test the study assumptions.

5.4.2 Unserved Load and Demand-Side Resources. The model simulations of PNW and WSCC systems identified time periods in which the projected load exceeded the amount of energy available to meet this load. When this situation occurred, the models reported this as unserved load and the number of megawatt hours in which this occurred was tabulated. In general the unserved load occurred in the model simulations during low water periods of the year, in low water years, and periods of high demand. The frequency and magnitude of this unserved load is discussed below. How to treat this unserved load is a critical element of the generation reliability issue.

One approach considered for treating the unserved load in this analysis was to assume that a curtailment in energy provided will occur and the user will suffer the economic losses. The appropriate value to assign to this curtailment is not known, but in some studies it has been assigned a relatively high value that exceeds the marginal costs of all thermal resources. This approach was used in the PROSYM model and was tested with the BPA model and this is discussed in section 5.4.3.

The approach that was used with the Aurora and BPA models recognized that market prices will affect power demands, and included demand-side management measures as potential resources to address unserved loads. This approach was chosen because with the movement from average embedded cost pricing in regulated markets to marginal cost pricing in competitive markets, a number of implications for both consumers and suppliers will occur. Competitive prices are likely to be more volatile than historical average prices. For example in the PSW, the demand for electricity is highest during the summer months when air conditioning equipment is used the most, and on a typical summer day the demand for electricity is lowest in the late evening and early morning and highest in the late afternoon. As a result, different generators, from lowest cost to highest cost, are brought on line during the course of the day to meet demand.

With average cost pricing, most consumers are unaware of the variation in operating costs across seasons and times of day. With competitive pricing, consumers and their suppliers may see more price volatility in the form of time-of-use prices, which will vary with the cost of producing power. This may create confusion for consumers, but it will also offer them the opportunity to reduce their electricity bills by altering the timing of their electricity use. Technologies are likely to develop to allow consumers, or their suppliers, to schedule their appliance usage to avoid high price periods. This analysis attempts to account for these probable demand-side resources in computing the capacity needs, market prices, and system production costs.

Instead of assuming curtailments will occur, the Aurora and BPA analyses assumed demand-side actions would be taken first to meet some of the peak demands. Section 4.3.7 described how the potential size of demand-side resources and their marginal costs were defined for this study. These resources were priced in blocks with each successive block being more costly. The demand-side resources were treated like any other resource in the dispatching routines. During periods of high demand when thermal and hydropower resources are nearing full dispatch, the models dispatch the blocks of demand-side resources as needed to meet load. The demand-side resources are considered in defining the marginal costs and production costs in the two models.

Since the demand-side resources are priced at relatively high levels, the extent to which they are dispatched will influence the optimizing routines and consequently help determine how many new resources would be built. To demonstrate the extent of the dispatch of demand-side resources, Figures 15 to 17 provide cumulative probability distributions for the amount of these resources based on the 50 different simulated water conditions. These are for alternatives A1 and A3, year 2010, the PNW medium loads, and are based on the BPA model. Figure 15 shows the annual summary, while the other two figures show results for the specific months of January and August. Figure 15 shows from an annual standpoint that for 50 percent of the 50 water years, about 73 aMW, or less, of demand-side resources were dispatched with alternative A1 in year 2010. This same figure shows that for alternative A3 only 46 aMW of demand-side resources were dispatched 50 percent of the time. Since the PNW load in this year is over 27,000 aMW, this shows that the use of demand-side resources is a very small component of total resources. However, on average, less demand-side resources were used with A3 because with this alternative more CC plants are available, and these plants are not limited in low water periods. This relationship is confirmed by the relationship shown between the cumulative distributions of A3 and A1 in the low water month of August. However, Figure 17 shows that for January slightly more demand-side resources were used with A1, but the frequency of this occurrence is very small.

FIGURE 15 Cumulative Probability Demand Side Resources for 2010 - Annual

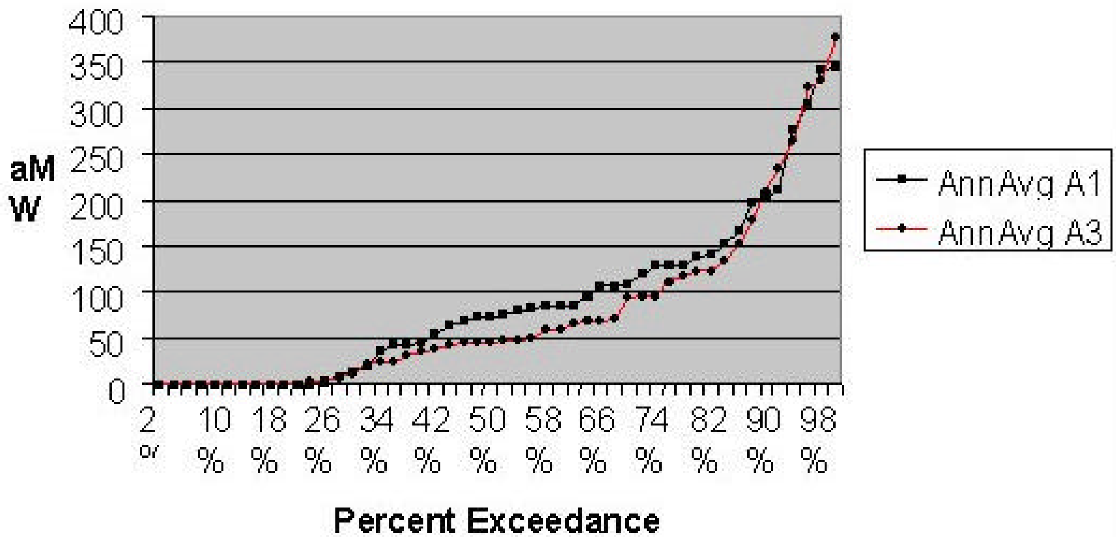
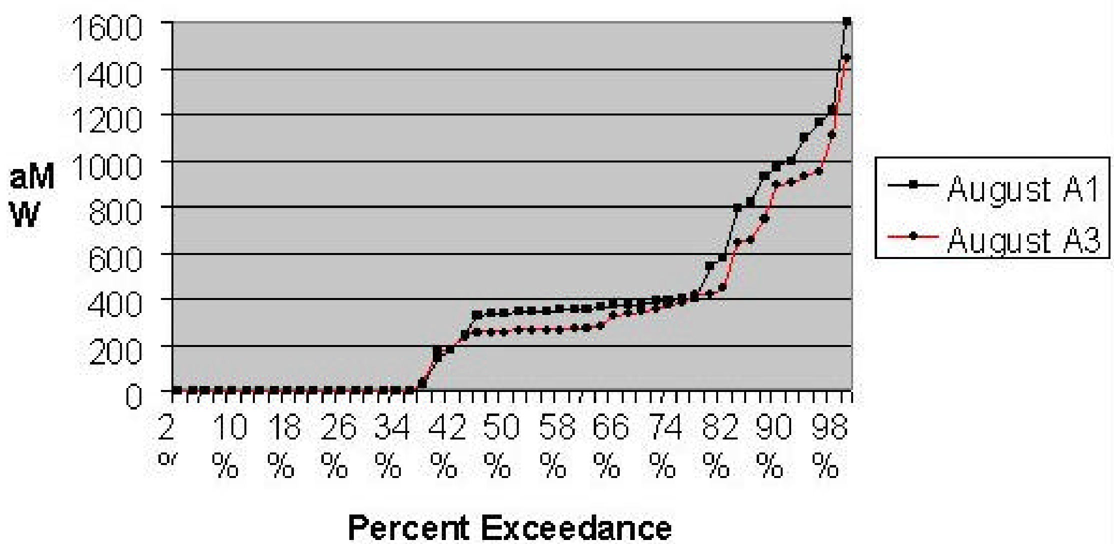
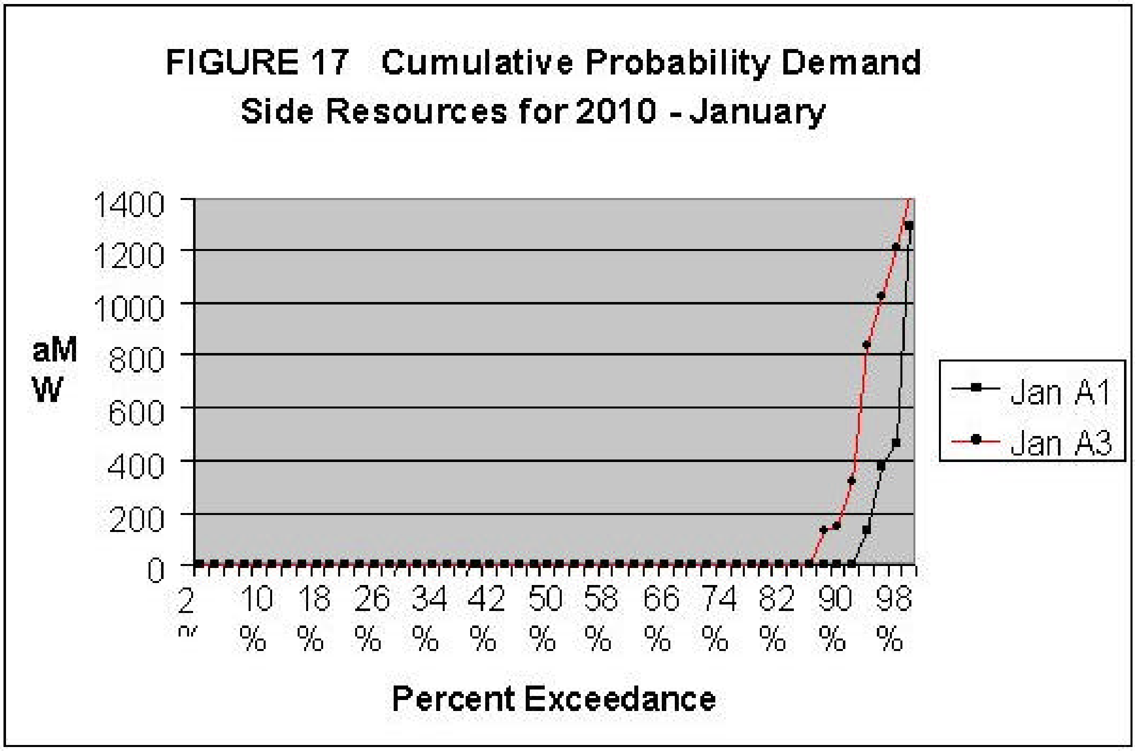


FIGURE 16 Cumulative Probability Demand Side Resources for 2010 - August





The Aurora and BPA models utilized the demand-side resources in the dispatch routines and the optimizing routine for additional resources. Table 25 shows the amount of new thermal resources that were added by the BPA model for specific years of simulations, by alternative, and by the regions of the PNW and PSW. As explained before, all of these thermal resources were assumed to be natural gas fired CCs. The resources shown for year 2010 and 2018 represent the cumulative amount of resources added up to the respective years. The table shows results in terms of average megawatts (aMW) and total MW of capacity added to the PNW and PSW. The fixed costs associated with these additions are included in the production costs shown in Tables 19 to 21.

Table 25
Resource Additions By Alternative
BPA Model Results For Specific Years

Alternative	2010			2018		
	PNW (aMW)	PSW (aMW)	Total (aMW)	PNW (aMW)	PSW (aMW)	Total (aMW)
A1	5,390	3,260	8,650	8,720	8,770	17,490
A2	5,380	3,190	8,570	8,710	8,760	17,470
A3	6,210	3,260	9,470	9,700	8,750	18,450
A5	6,080	3,260	9,340	9,610	8,820	18,430
A6a	5,410	3,210	8,620	8,610	8,770	17,380
A6b	5,480	3,200	8,680	8,680	8,770	17,450
B1	7,000	3,260	10,260	10,590	8,770	19,360
B2			--			--
C1	6,660	3,260	9,920	10,220	8,770	18,990
C2			--			--
Difference From Base Condition (aMW)						
A1 A2 A3 A5 A6a A6b B1 B2 C1 C2	(10) 820 690 20 90 1,610 1,270	(70) -- -- (50) (60) -- --	(80) 820 690 9(30) 30 1,610 1,270	(10) 980 890 (110) (40) 1,870 1,500	(10) (20) 50 -- -- -- --	(20) 960 940 (110) (40) 1,870 1,500
Difference From Base Condition (MW)						
A1 A2 A3 A5 A6a A6b B1 B2 C1 C2	(10) 890 750 20 100 1,750 -- 1,380 --	(80) -- -- (50) (70) -- -- -- --	(90) 890 750 (30) 30 1,750 -- 1,380 --	(10) 1,070 970 (120) (40) 2,030 -- 1,630 --	(10) (20) 50 -- -- -- -- -- --	(20) 1,040 1,020 (120) (40) 2,030 -- 1,630 --

The PROSYM model does not include system expansion components, so the user specifies when additional resources should be added to the resource mix. The resource additions identified by the BPA model were added to the PROSYM dispatch.

5.4.3 Test of Unserved Load Approach. The study team decided to test the treatment of unserved load and the economic value assigned to it. Of interest was how pricing unserved load and demand-side resources influenced the construction of new capacity.

As discussed in section 4.3.7 the unserved load was met in the BPA and Aurora models by demand-side resources that were valued in blocks. The range of values (marginal costs) were from 50 to 500 mills/kWh depending on the size of unserved load. If any unserved load still occurred after dispatching all demand-side resources, it was assigned a marginal cost of 1,000 mills/kWh. Section 5.4.2 demonstrated that with these pricing assumptions the demand-side resources were used infrequently to meet load.

To determine how significant these assumed block sizes and prices were, a test analysis was undertaken. In this test the BPA model was run by replacing all costs of demand-side resources and any unserved loads with a cost of 5,000 mills/kWh. The test was done only for alternatives A1 and A3, for year 2010. Table 26 shows the resources that were added to the PNW and PSW and the system production costs in this test case and the original analysis, up to year 2010. As expected, with this higher cost for unserved load, more new resources were found to be economical and were added by the model. In the test case the amount of new CC resources built in year 2010 was 15,690 aMW in the PNW and PSW with alternative A1, and 16,420 aMW with A3. This is an increase from the original analysis of 7,040 and 6,950 for A1 and A3, respectively.

Table 26
Unserved Load Approach Test
Resource Additions and Production Costs
Medium Projections, Year 2020

Alternatives	Test Case[1]	Original Case[2]	Test - Original
New Resources (aMW)			
A1	15,690	8,650	7,040
A3	16,420	9,470	6,950
Difference A3-A1	730	820	(90)
System Production Costs (1998 $ Millions)			
A1	$5,224	$4,335	$889
A3	$5,408	$4,582	$826
Difference A3-A1	$184	$247	($63)

[1]Assigned 5,000 mills/kWh marginal cost to all unserved load.
[2]Assigned blocks of marginal cost from 50 to 1000 mills/kWh to unserved load.

The increase in the amount of new resources in the test case reflected that new resources could capture the high values to a large enough extent to economically justify their construction. That is, new resources could be justified with lower plant factors than in the original analysis. Also, in the test case fewer resources (90 aMW) were added in A3 when compared to A1. This can be explained by the fact that in the base condition (A1), under the test case, the power system included many CC plants with relatively low plant factors. When the Lower Snake River projects are removed under alternative A3, less new resources are needed to replace them because the plant factors of the new CC plants increased to meet the load.

The amount of new resource additions is not the only significant factor to examine. The total system production costs in the test and the original cases were also compared. The total system production costs with the test case increased significantly from the original case, $889 million and $826 million for A1 and A3, respectively. These higher total system production costs were due to the costs of adding about 7,000 additional aMW of new CC capacity. However, the variable production costs, relative to the original case, dropped in the test case. The new CC resources (about 7,000 aMW in the test case) are more efficient and have lower variable costs than many of the existing resources in the resource mix. With more of these relatively efficient resources available for the model (in the test case) to dispatch to meet the load, the use of older resources with higher variable costs was reduced.

The changes in total system production costs between alternatives A1 and A3 under both cases yielded some interesting results. It was found that the net total system production costs between A1 and A3 in the test case was $184 million. In the original case the total system production costs increase was $247 million. That is, that breaching the Lower Snake River dams does increase total system production costs, but the increase was somewhat less in the test case. This 25 percent reduction resulted from the assumption of over a five-fold increase in the value of unserved load. Generally, it was found that losing the Lower Snake River powerplants in a system with lots of excess capacity is not as costly as losing the plants in the original case.

In conclusion, this test showed that the treatment of the value the unserved load in the model influences the amount of new thermal resources that are built by the model. Assigning a very high value to unserved load will result in more new CC capacity and substantial increases in the total system production costs (*i.e.*, variable costs + fixed costs). However, the increase in fixed costs from adding more CCs are partially offset by reduced variable production costs. It was found that in both the test and original cases the total system production costs increased with the removal of the Lower Snake River Dams. However, the valuing of unserved load did somewhat influence the magnitude of the total system production costs associated with removing the dams. The significance of this influence appeared to be relatively small when compared to the substantial increase in the value of unserved load used in the test case. But, the study team decided to further examine the relationship of increasing fixed cost and reducing variable costs with capacity additions. The next section examines the significance of capacity additions to total system production costs.

5.4.4 System Reserves and Dependable Capacity Examination. As with any assessment of system reliability, criteria of acceptable reliability need to be devised and defined. Various criteria have been used historically in California and elsewhere in the West. These criteria have differed depending on the type of study, planning or operating, and the time period of the study. One measurement tool has been the planning reserve margin, which is expressed as a percentage of generation capability in excess of peak demand. The "correct" level of planning reserves in a deregulated market has yet to be established, and many argue that this level should be an economic decision made by market participants.[7]

The type of criteria that may be developed in the future is hard to determine at this time. The WSCC has operated under a number of voluntary criteria and these reliability criteria are currently under examination for revision. For example WSCC has a Minimum Operating Reliability Criteria (MORC). The MORC defines goals of operating the system with adequate levels of generating reserves to account for a multitude of possible conditions to preserve the power system and insure reliable delivery of energy throughout the WSCC. This sets criteria for operating reserves, spinning reserves, voltage control, reactive power, transmission path restrictions, and numerous other operational considerations.

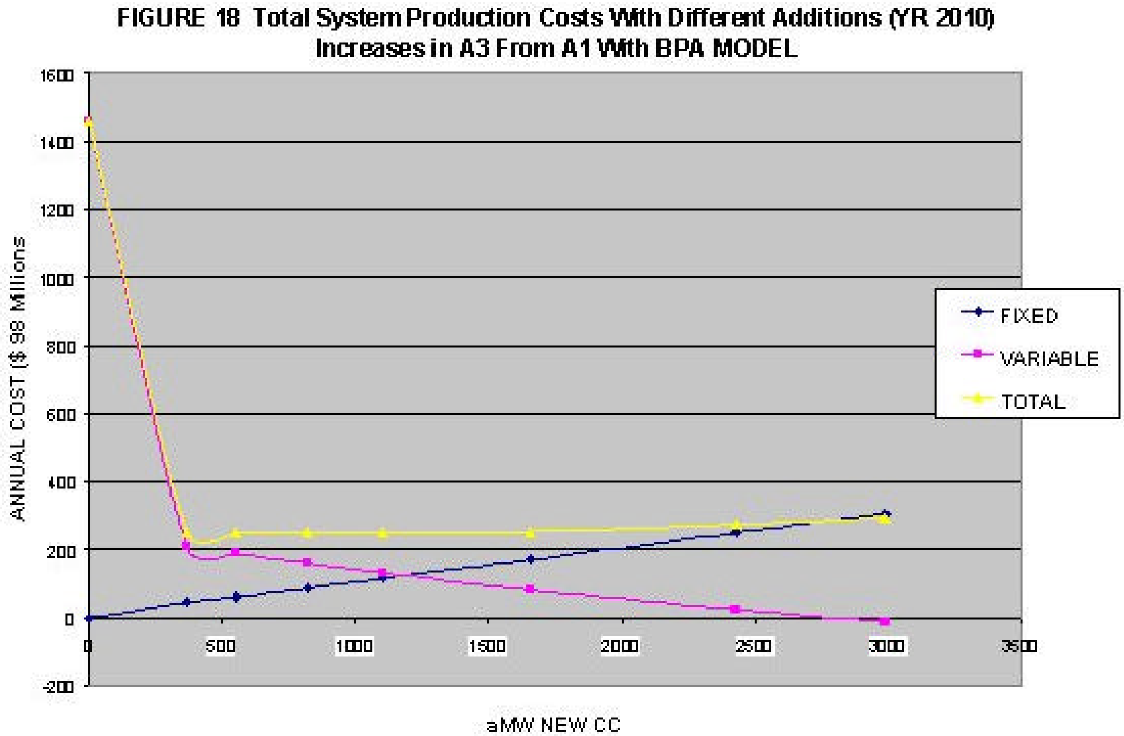
Currently, there is no legal authority to require any entity in the WSCC to participate in a mandatory reliability program with sanctions, but alternative approaches such as contractual agreements are being considered. The WSCC is presently examining new criteria to be implemented in the current open access market. This process is called the Reliability Management System (RMS) which is being implemented in three phases. In addition, at the national level, legislation is being developed for the North American Electric Reliability Organization (NAERO) to act as a policing authority similar to the Securities and Exchange Commission (SEC) for the stock market. Based on direction by FERC there currently exist Area Security Coordinators throughout the nation to assure system stability over all transmission areas.

Based on all these proposals and their uncertainty, any attempt at this time to specifically define a set of reliability criteria would be subject to criticism and would be likely to change before any of the Lower Snake River alternatives could be implemented. For this reason, the study team examined the effects of different reliability criteria on the net economic effects. In particular the team looked at the A3 alternative (changes from A1) with medium economic forecasts, in a specific year of 2010. Varying levels of additional new generating capacity were examined with the BPA and PROSYM models. The different amounts of new capacity resulted in different levels of system reserves (hence reliability) in the PNW and different system production costs.

The amount of additional CC generation capacity assumed to be built by year 2010 under alternative A3 was computed by the BPA model to be 890 MW as shown in Table 25. The determination of alternative levels of new capacity additions to consider in this test was based on the more traditional dependable capacity approaches. The approaches used were: (1) To define a dependable capacity level of the existing Lower Snake River plants based on a recent study done by the Corps of Engineers. This study examined numerous criteria to define dependable capacity and recommended 2,640 MW for the combination of all four Lower Snake River dams. (2) The PROSYM model was used to identify the level of new CC capacity that would need to be in place in year 2010 to maintain the PNW planning reserve margin at 12% for both A1 and A3. To achieve this level of reserves A3 required an additional 3,250 MW of new capacity. For the different test scenarios, these levels of new capacity were assumed to be built with A3. This is in addition to the level of new resources that were assumed to be built with the base condition (A1) by year 2010.

Utilizing the BPA model the three different levels of new capacity were modeled to see how total system production costs (variable costs + fixed costs of new resources) would change. In addition, a scenario in which no additional resources were added above those assumed to occur with alternative A1 was also tested. The installed capacity additions discussed above were defined in terms of aMW for utilization in the BPA model. For example, the installed capacity for the scenarios of 0, 890, 2640, and 3250 in MW, were 0, 820, 2430, and 2990, respectively, in terms of aMW to account for average availability.

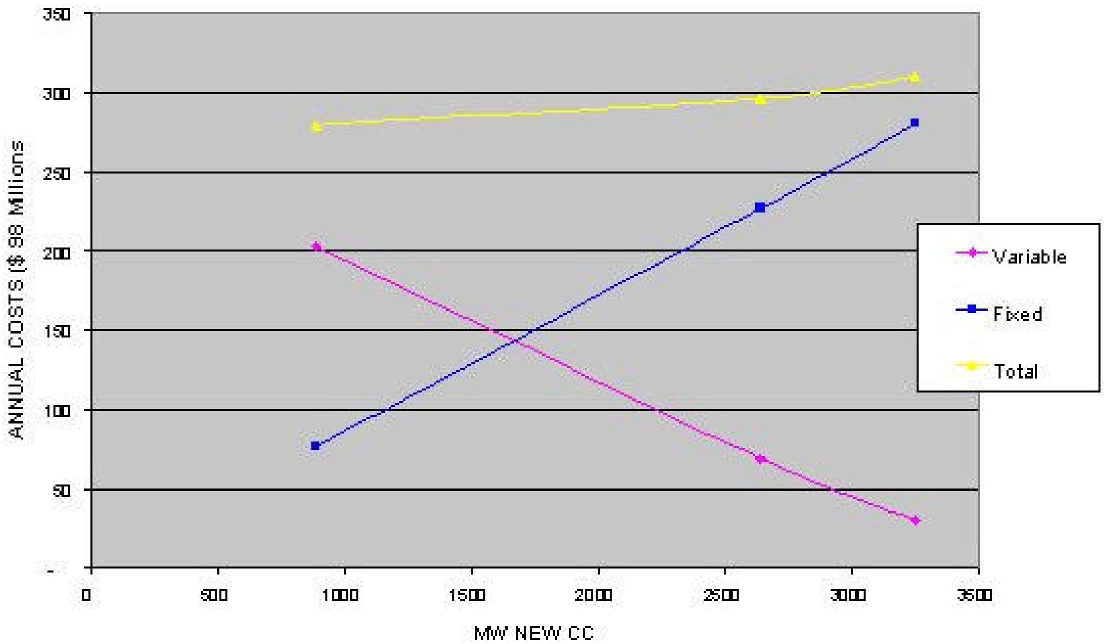
Figure 18 shows the results from the BPA model for these different scenarios. The figure shows the variable costs (production costs), the fixed costs (new capacity costs), and the total costs (total system production costs). Figure 18 shows the capacity addition level in which total system production costs are at their minimum. It can be concluded from this figure that the addition of 890 MW (820 aMW) of new capacity is at or near the point of economic optimum (point of minimal net economic costs). This was expected because the BPA model utilized an optimization routine to define the 890 MW level. One interesting point from this figure is at around 2700 aMW of new additions the system variable costs go below zero. This means that if enough new CC plants are added to the system, with the removal of Lower Snake Dams, the system production costs (variable costs) will be less than if the dams were not removed. However, the fixed costs of these high level of capacity additions are so large that the total system production costs (variable + fixed) are much higher (about $300 million annually) than the base condition. The relatively flat slope of the total cost curve suggests that the selection of the most appropriate new capacity level may not be an extremely sensitive element of the hydropower study. For example, if the traditional dependable capacity approach was used the total system production costs would increase from $248 million to $273 million annually which is only a 10 percent increase. This increase in annual costs could be construed as the costs of improving system reliability.



Note: The dip in the curve at approximately 550 aMW is a software graphing anomaly. Actual minimum is at 820 aMW.

This same type of analysis was done with the PROSYM model for the new capacity additions with A3 of 890 MW, 2640 MW, and 3250 MW in year 2010. The PROSYM test is shown in Figure 19. The total system production costs with this model are higher than with the BPA model as discussed in section 5.2.3. The capacity additions shown in Figure 19 are in terms of installed MW rather than aMW shown in the previous figure. A zero capacity addition scenario with A3 was not tested with PROSYM, so the left-most part of the graph is not shown. As can be seen the same basic conclusion can be reached from results from the PROSYM model figure, namely, the selection of capacity replacement approach does not appear to be critical to the relative magnitude of the change in total system production costs.

FIGURE 19 Total System Production Costs With Different Additions (Year 2010) - Increases In A3 From A1 - PROSYM Model



The PROSYM model provides the planning reserve margin for each of the transmission areas in the model. The planning reserve margin is the percent of generation capacity in excess of the highest peak load hour in the year. The planning reserve margins for all regions except the PNW were the same for alternatives A1 and A3. The different levels of new capacity shown in Figure 19 had planning reserves in year 2010 of 4%, 10%, and 12% for additions of 890 MW, 2640 MW, and 3250 MW, respectively.

5.4.5 Reliability and Capacity Conclusions. This section presented the basic elements of the study dealing with additions of new generating capacity to replace the lost capacity associated with the breaching of the four Lower Snake Dams. The replacement of the lost capacity relates to the general reliability of the power system over time and to what extent the market might pay for additional reliability. One complicating element of this hydropower analysis was the projection of what society might pick as the most appropriate reliability criteria in the study period of 2005 and beyond. The approach used in this study to estimate what level of new capacity would be built was to do an economic optimization to determine what level of new resources could be economically justified for construction. The study team, however, wanted to test the study results against other possible levels of new capacity and related generation reliability.

The study team was concerned whether different levels of replacement capacity and different approaches to the treatment of unserved loads would significantly change the estimates of increased system production costs. These two factors were tested with different approaches that lead to different levels on new capacity and planning reserve margins. With the higher levels of new generating capacity, the planning reserves were higher but so were the system production costs. However, it was found that the total system production costs were not extremely sensitive (on a percentage basis) to different levels of assumed new generating capacity. So, the study team was satisfied that the capacity addition approach used in this analysis represented a reasonable estimate of the economic effects associated with the alternatives.

5.5 SYSTEM TRANSMISSION EFFECTS

The purpose of this section is to identify the costs associated with maintaining transmission reliability with the breaching of the Lower Snake River Dams. This section investigates the impacts to the Northwest transmission grid with alternatives A3 and A5. The A2 and A6 alternatives are not expected to have any significant impact to the transmission grid. The transmission impacts associated with alternatives B1 and C1 are not identified here because they are beyond the scope of study.

The primary source of information for this analysis is the January 1999 report, *Transmission Impacts of Breaching the Lower Snake and John Day Dams.* This report was prepared by the Transmission Business Line organization of BPA, and is included as an attachment to this report in the Technical Exhibit C. For this section, some adjustments were made to the cost estimates and timing of impacts in the Technical Exhibit to be consistent with the discount rates and period of analysis used in the rest of this analysis.

The A3 and A5 alternatives would breach the four Lower Snake dams, rendering the powerhouses inoperable, and thereby altering the source of power generation that feeds into the Northwest transmission grid. Since the transmission grid was originally constructed in combination with the generation system and since they interact electrically, loss of generation will affect the transmission system's ability to move bulk power and serve regional loads.

5.5.1 Study Approach. Numerous changes will occur on the transmission system between now and 2006. However, many of these changes will have to occur regardless of the status of the dams in question. Therefore, 1998 and 1999 system conditions were used as a baseline since the most accurate transmission system capability is available for this timeframe. Results from these studies were extrapolated to 2006 conditions. It was assumed that the measures needed to maintain the transmission system reliability would be constructed in year 2006, so measures would be functioning in the first full year of dam breaching in year 2007.

The study looked at transmission system impacts with and without replacement generation. Both transmission system reinforcements and generation additions were evaluated to mitigate the transmission system impacts caused by breaching the four Lower Snake dams. The initial phase of this transmission study assumed no replacement generation for the dams that are breached. The transmission improvements needed to maintain reliable service were then identified and costs estimates were prepared. However, it was recognized that the construction and location of replacement generating resources would have a profound effect on the transmission system impacts and reinforcement needs and may provide a most cost-effective solution. This phase of the study was done separately from the energy supply analysis in sections 5.1 to 5.4. The energy supply studies indicated that alternatives A3 and A5 require 890 MW of new CC generation in 2010 to replace lost hydropower. This transmission study evaluated transmission system requirements if replacement generation were constructed in a location where it would provide transmission system benefits to mitigate the loss of hydropower. To the extent that more than 890 MW of new CC generation will be required for transmission reliability, the additional costs are added to this transmission section.

Preliminary cost estimates for capital additions are included in this summary. These costs are based on preliminary studies using typical costs for facilities. A range of cost is given since there is much uncertainty about load growth, new resources, the scope of the projects, routes, etc which could affect project cost.

Transmission impacts were examined for two seasonal conditions, the summer and the winter peak situations. The following defines the expected impacts and the possible solutions. The study approach was to first identify the impact to the transmission system, then the possible solutions were examined. The final step of the analysis was to select the most cost-effective measure to address the identified transmission impact.

5.5.2 Summer Impacts. The summertime peaks are the largest in the PSW and transmission from the PNW over the California-Oregon Intertie/Pacific Direct Current Intertie (COI/PDCI) is important to meeting the PSW demands.

5.5.2.1 Northwest to California Transfers. If the Lower Snake dams are breached, and not replaced, the COI/PDCI transfers limits decrease by 200 MW (from 7200 to 7000 MW). This would limit the ability to sell and transfer PNW generation to the PSW to meet peak demands. Three possible solutions were postulated, (1) reduce the COI/PDCI capacity by 200 MW and incur loses in sales. The economic costs of this approach were not quantified. (2) Upgrade the COI/PDCI intertie to maintain its capacity at a cost of $65 million to $85 million. (3) Site thermal replacement plants in the locations that would reinforce intertie transfer capabilities. It was found that these solutions to the summer impacts were not needed because the solutions to the winter problems also corrected these impacts

5.5.2.2 Northwest Regional Impacts. With the loss the four Lower Snake dams, there is more stress on the transfer capability in the Upper Mid-Columbia area. Two transmission system cutplanes, North of John Day and North of Hanford are impacted. (A cutplane is a group of transmission lines whose total loading is an indicator of system stress.) These particular cutplanes measure how much power is flowing from the Upper and Mid Columbia area to COI/PDCI. With the elimination of generation from the Lower Snake Projects and a desire to have the same level of north to south transfers on the COI/PDCI, the flow across the cutplanes must increase. In other words, the generation from the Lower Snake Projects is replaced with generation from Chief Joseph, Grand Coulee and other northern and eastern powerplants. However, with this increase in generation, capacities across these cutplanes are exceeded. Thus, the cutplane flows must be limited, which in turn causes a reduction in the COI/PDCI transfer capability. In the summer this reduction in COI/PDCI transfer is 200 MW as noted above in 5.5.2.1. Said slightly differently, when the capability of these cutplanes is exceeded, typically reductions in COI/PDCI transfer are necessary to bring the flow across the cutplanes back within capability limits. Therefore, a reduction in cutplane capability means that the opportunity and flexibility to use the full COI/PDCI transfer capability is reduced. To increase cutplane capability an improvement to the Schulz-Hanford transmission line and facilities is required. The estimated costs were $50 to $75 million.

5.5.2.3 Montana to Northwest Transfer Capability. The West of Hatwai capability is reduced about 500 MW if the Lower Snake dams are breached. This means that transfers from Montana and/or Western Montana Hydro will need to be reduced to maintain the Hatwai limit. Previous studies have shown that these problems would be mitigated with a Bell-Ashe 500-kilovolt (kV) line from Spokane to the Tri-Cities area. This line would require a new transmission corridor and cost between $100 million to $150 million.

5.5.2.4 Load Service. The Tri-Cities area, south of Spokane and Central Washington load areas are negatively affected by dam removal scenarios. Specific transmission impacts are different depending on the location of replacement generation. Preliminary estimates to reduce the thermal overload impacts to load centers are between $10 and $20 million. The measures include reconductoring/rebuilding underlying 230/115-kV lines, and sectionalizing existing lines.

Additional voltage support is also needed in summer in these areas if the four Lower Snake dams are breached. Converting the generators at a hydropower plant to synchronous condensers is an effective and low-cost way to produce reactive support required to fix this voltage support problem for Tri-Cities area loads. This could be accomplished with converting the generators at Ice Harbor. Preliminary cost estimates for this conversion were $2 to $6 million.

5.5.3 Winter Impacts. The impacts to the transmission system under extreme winter load conditions in the PNW were examined. An extreme cold winter load condition was examined since stress on the system is high under extreme weather. The extreme cold winter load level is an abnormal cold condition (arctic express) with minimum temperatures that have a 5% probability of occurring. The extreme cold winter load level is approximately 12% higher than the expected normal winter peak that has a 50% probability of occurring. This is the criteria BPA customers have agreed to in the past.

It was found that imports from the California interties could not meet the shortfall created by the loss of the Lower Snake dams. The import capability today on the COI/PDCI with the dams in place is around 2,400 MW during extreme winter load conditions. This 2,400 MW capability is needed today, with the four Lower Snake dams in place, to augment available generation and spinning reserve requirements in the PNW. Without the four Lower Snake dams, either more intertie, or more local generation is required to meet system loads and maintain system reliability. The possible solutions examined were to develop replacement generation or to improve the COI/PDCI. The analysis shows that replacement generation is about half as costly as intertie transmission improvements.

5.5.3.1 PNW Replacement Generation. With the removal of the Lower Snake River dams it was found that 1,550 MW of new generating resources (replacement generation) strategically located in the PNW would be sufficient to meet the winter extreme conditions, if the COI/PDCI was not improved. This is about 510 MW more of replacement generation than is required for energy alone.

The new capacity assumed to be built in the future to replace energy lost under alternatives A3 and A5 was described in section 5.4, and in Table 25. The net economic costs identified in this technical report for A3 were based on adding 890 MW of new PNW generating resources by year 2010 and 1,040 MW by year 2018. But this takes care of only regional energy losses at the breached dams. The winter transmission impacts of breaching could be mitigated if 1,550 MW of replacement generating resources were in place at the time of breaching of the Lower Snake River Dams (2007). The transmission system impacts of breaching would require more generation in place sooner (1,550 MW in 2006 versus 890 MW in 2010 and 1,040 in 2018).

The costs of providing additional replacement generation were examined using the system production cost approach as computed by the BPA model. It was assumed that the additional replacement resources would be installed in year 2006 and will be available for service when the generation from the Lower Snake River plants would be lost in year 2007. Table 27 provides the annual difference in system production costs between the original amount (1,040 MW in 2018) of replacement generation required for energy and 1,550 MW of replacement generation in 2007 required for transmission reliability. The replacement capacity assumed to be built elsewhere in this analysis was 1,040 MW through year 2018 as shown in Table 25. So, to meet transmission reliability needs an additional 510 MW (1,550 -- 1,040) of generation capacity will need to be constructed in PNW. Based on the CC construction costs of $601,000 per MW, the additional construction costs of replacement thermal will be about $306 million.

These increased costs will be somewhat offset by the expected reduction in system variable costs from adding more generation than is required for energy alone. Both the construction costs and variable costs are included in the total system production costs in Table 27. The annual economic costs associated with the additional generation capacity were $8.9 million at the 6.875% discount rate.

Table 27
System Production Cost Increases
Due To Transmission Impacts
Net Increase in System Production Costs (SPC)[1]
($ 1998 Millions)

Year	Original SPC A3 - A1	SPC With 1,550 MW A3 - A1	Difference Associated With Transmission
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 - 2106	-- 239.9 241.9 244.0 245.5 247.0 249.1 251.1 252.7 254.2 256.3 258.3 260.4	-- 247.0 248.6 250.1 252.2 254.2 254.2 256.3 258.3 260.9 263.4 266.0 268.6 271.1	-- 7.2 6.7 6.2 6.7 7.2 7.2 7.2 8.2 9.2 10.3 10.8
		NPV @ 6.875% NPV @ 4.75% NPV @ 0.0%	$128.9 193.2 1,028.5
		AAE @ 6.875% AAE @ 4.75% AAE @ 0.0%	8.9 9.3 10.3

[1]Assumes new capacity of 1,550 is constructed in year 2006.
The original System Production Costs were based on the new capacity shown in table 25.

5.5.3.2 Improvements to COI/PDCI. The alternative solution to building new replacement capacity is intertie transmission system reinforcements. The improvements needed to meet load service requirements for extreme winter conditions include: a second Captain Jack-Meridian 500-kV line (a cross cascades line from Klamath Falls to Medford) and a second Big Eddy-Ostrander 500-kV line (a cross cascades line from The Dalles to Portland). The estimated construction costs for the Captain Jack Meridian line improvements were estimated at $80 to $130 million. The improvements to the Big Eddy-Ostrander line would cost from $70 to $120 million. The average annual costs of these two lines considering O&M, R, R, computed at 6.875%, were $5.6 to $9.0 million for Captain Jack Meridian and $4.9 to $8.3 million for Big Eddy-Ostrander. The mitigation costs of the transmission solution are about twice as expensive as the generation solution.

5.5.3.3 Local Load Service Limitations. There are also winter time load service limitations in the Tri-Cities area for extreme cold winter conditions if the Lower Snake dams are breached. A new 230/115-kV transformer in the Franklin area would be required. The estimated cost for adding this transformer is between $15 million and $25 million.

5.5.4 New Resource Location. Where new generation resources are located is an important issue and confounds the different responses that could be taken to address the loss of the Lower Snake River projects. Adding new generation in the Grand Coulee and Spokane area will help Portland load service problems but aggravate Seattle load service problems. Also, this would aggravate North of John Day and North of Hanford cutplanes problems during the summer.

Adding generation in the load areas west of the Cascades helps winter load service problems, but will significantly aggravate I-5 corridor north to south problems in the summer. Correcting these transmission system problems would be difficult and expensive.

Adding generation in the Hermiston area will result in similar COI/PDCI capability for the summer since it is south of the North of John Day cutplane. However, west of McNary problems may be created due to displacing Ice Harbor and John Day generation, which would be offset by the breaching of Lower Monumental, Little Goose and Lower Granite dams.

Replacement of hydro generation with an equal amount of thermal generation -- even if it’s in the same location is not necessarily equivalent with respect to transmission capability. The response of hydro generation is superior to that of thermal generators during transient time periods. Transmission system reinforcements are generally necessary to maintain the same transfer capacity even if the losses are replaced MW for MW at the same location.

5.5.5 Summary of Transmission Effects. Tables 28 to 30 provide the possible solutions and related annual costs based on the three different discount rates. These tables are broken into the impact areas and possible solutions. For each impact the lowest cost solution is recommended and included in the total economic effects.

Tables 28 to 30 show the range of construction costs as estimated by BPA. Also shown are the incremental O&M costs that would occur if the transmission improvements were built. To develop the annual costs associated with these measures a 45-year replacement cycle was assumed.

Table 28
Transmission Impacts With Alternative A3
Annual Values Based on 6.875%

Timing/Location of Impacts	Impact Description	Possible Solutions	Estimated Construction Costs ($ Millions)	Incremental O&M Costs ($ Millions)	Total Annual Costs ($ Millions)	Selected Solution Average Annual Costs ($ Millions)
Summer: NW to California	Transfer limit is reduced (a cutplane problem)	Limit COI/PDCI transfer capability from 7200 MW to 7000 MW	Not quantified			
		Upgrade the COI/PDCI	65 to 85	0.30	5.1 to 5.9	
		Site thermal replacement plants to reduce impact	Not quantified			Siting 1550 MW for winter solves this problem.
Summer: Upper/Mid Columbia	Thermal overloads	Improve Schultz-Hanford line	50 to 75	0.17	3.6 to 5.2	3.6 to 5.2
Summer: Within Northwest	Voltage support to the Tri-Cities	Ice Harbor generators converted to synchronous condensers	2 to 6	0.20	0.4 to 0.6	0.4 to 0.6
Summer: Montana transfer to Northwest	Transfer limit is reduced by 500 MW	Build Bell- Ashe and Spokane to Tri-Cities 500 kV lines	100 to 150	0.38	7.2 to 10.5	7.2 to 10.5
Summer: Canada to Northwest	Increased congestion on I-5 transmission corridor	No solution offered	Not quantified			
Summer: Tri-Cities	Load service impacted	Local line transmission improvements	10 to 20	0.00	0.7 to 1.4	0.7 to 1.4
Winter: Meeting extreme winter loads	Import capability is reduced and results in inability to meet extreme loads	Site 1550 MW of replacement generation	306 capital costs for generation	Included in annual costs	8.9	8.9
		New transmission line - Capt Jack - Meridian	80 to 130	0.2	5.6 to 9.0	
		New transmission line - Big Eddy - Ostander	70 to 120	0.2	4.9 to 8.3	

Winter: Tri-Cities	Load service limitations	Local transmission improvements - McNary - Franklin	15 to 20	0.1	1.1 to 1.5	1.1 to 1.5
		Totals[1]	**$483 to $577**			**$21.9 to $28.1**
[1]Includes only costs for selected solutions.						

Table 29
Transmission Impacts With Alternative A3
Annual Values Based on 4.75%

Timing/Location of Impacts	Impact Description	Possible Solutions	Estimated Construction Costs ($ Millions)	Incremental O&M Costs ($ Millions)	Total Annual Costs ($ Millions)	Selected Solution Average Annual Costs ($ Millions)
Summer: NW to California	Transfer limit is reduced (a cutplane problem)	Limit COI/PDCI transfer capability from 7200 MW to 7000 MW	Not quantified			
		Upgrade the COI/PDCI	65 to 85	0.30	4.0 to 4.6	
		Site thermal replacement plants to reduce impact	Not quantified			Siting 1550 MW for winter solves this problem.
Summer: Upper/Mid Columbia	Thermal overloads	Improve Schultz-Hanford line	50 to 75	0.17	2.8 to 4.1	2.8 to 4.1
Summer: Within Northwest	Voltage support to the Tri-Cities	Ice Harbor generators converted to synchronous condensers	2 to 6	0.20	0.3 to 0.5	0.3 to 0.5
Summer: Montana transfer to Northwest	Transfer limit is reduced by 500 MW	Build Bell- Ashe and Spokane to Tri-Cities 500 kV lines	100 to 150	0.38	5.6 to 8.2	5.6 to 8.2
Summer: Canada to Northwest	Increased congestion on I-5 transmission corridor	No solution offered	Not quantified			

Summer: Tri-Cities	Load service impacted	Local line transmission improvements	10 to 20	0.00	0.5 to 1.0	0.5 to 1.0
Winter: Meeting extreme winter loads	Import capability is reduced and results in inability to meet extreme loads	Site 1550 MW of replacement generation	306 capital costs for generation	Included in annual costs	9.3	9.3
		New transmission line - Capt Jack - Meridian	80 to 130	0.2	4.4 to 7.0	
		New transmission line - Big Eddy - Ostander	70 to 120	0.2	3.8 to 6.4	
Winter: Tri-Cities	Load service limitations	Local transmission improvements - McNary - Franklin	15 to 20	0.1	0.9 to 1.1	0.9 to 1.1
		Totals[1]	**$483 to $577**			**$19.4 to $24.2**

[1]Includes only costs for selected solutions.

Table 30
Transmission Impacts With Alternative A3
Annual Values Based on 6.875%

Timing/ Location of Impacts	Impact Description	**Possible Solutions**	**Estimated Construction Costs ($ Millions)**	**Incremental O&M Costs ($ Millions)**	**Total Annual Costs ($ Millions)**	**Selected Solution Average Annual Costs ($ Millions)**
Summer: NW to California	Transfer limit is reduced (a cutplane problem)	Limit COI/PDCI transfer capability from 7200 MW to 7000 MW	Not quantified			
		Upgrade the COI/PDCI	65 to 85	0.30	2.0 to 2.4	
		Site thermal replacement plants to reduce impact	Not quantified			Siting 1550 MW for winter solves this problem.
Summer: Upper/Mid Columbia	Thermal overloads	Improve Schultz-Hanford line	50 to 75	0.17	1.4 to 2.0	1.4 to 2.0

Summer: Within Northwest	Voltage support to the Tri-Cities	Ice Harbor generators converted to synchronous condensers	2 to 6	0.20	0.2 to 0.4	0.2 to 0.4
Summer: Montana transfer to Northwest	Transfer limit is reduced by 500 MW	Build Bell- Ashe and Spokane to Tri-Cities 500 kV lines	100 to 150	0.38	2.9 to 4.1	2.9 to 4.1
Summer: Canada to Northwest	Increased congestion on I-5 transmission corridor	No solution offered	Not quantified			
Summer: Tri-Cities	Load service impacted	Local line transmission improvements	10 to 20	0.00	0.3 to 0.5	0.3 to 0.5
Winter: Meeting extreme winter loads	Import capability is reduced and results in inability to meet extreme loads	Site 1550 MW of replacement generation	306 capital costs for generation	Included in annual costs	10.3	10.3
		New transmission line - Capt Jack - Meridian	80 to 130	0.2	2.2 to 3.5	
		New transmission line - Big Eddy - Ostander	70 to 120	0.2	1.9 to 3.2	
Winter: Tri-Cities	Load service limitations	Local transmission improvements - McNary - Franklin	15 to 20	0.1	0.5 to 0.6	0.5 to 0.6
		Totals[1]	**$483 to $577**			**$15.6 to $17.9**

[1]Includes only costs for selected solutions.

As can be seen from these tables the annual costs associated with improvements needed to maintain transmission reliability with the breaching of the four Lower Snake River dams is about $22 to $28 million at 6.875%, $19 to $24 million at 4.75%, and $16 to $18 million at 0.0%.

5.6 ANCILLARY SERVICES EFFECTS

This section discusses the ancillary services and the estimated economic values of these services provided by the four Lower Snake River projects. These ancillary services are in addition to the energy, capacity, and transmission support benefits discussed elsewhere in this report. With the open access transmission ruling of the FERC, power suppliers are now charging separately for many of the ancillary services that in the past were generally bundled into the electricity rate by the entities owning the transmission facilities. Starting in 1998 BPA has begun to sell these ancillary services. Since these services are a necessary element of a safe and reliability power system, the loss of these services represents economic costs that must be accounted for in this analysis.

The four hydropower plants are connected to the Automatic Generation Control System (AGC) that regulates electricity generation at each dam, second by second, to keep the system's operating frequency as close to 60 cycles per second as possible. Generation at these dams is also varied, hour by hour, to accommodate the morning and evening swings in demand. During parts of the year idle units are counted as part of the Federal system's reserve requirement that provides backup for emergency situations.

The following provides explanation of the net economic costs that would occur with the removal of the four Lower Snake River dams with alternatives A3 and A5. The changes in ancillary services for alternatives A2 and A6 were assumed to be zero. Estimates of lost value for ancillary services for alternatives involving the John Day project were not computed for this report.

5.6.1 Automatic Generation Control (AGC). Many of the hydropower plants in the Federal system in the PNW are used for AGC. To provide AGC benefits to the system small, but very frequent changes in generation are necessary. Hydroelectric projects, with stored water as their fuel, are extremely flexible and very useful for this purpose. If the four Lower Snake dams are removed, their contribution to this system would have to be spread over the remaining projects (hence reducing their AGC benefits), or replaced by purchasing that service from other sources.[8]

To value the AGC the BPA staff that deals with market sales of ancillary services was consulted. BPA identifies which hydropower plants will be used for AGC on a scheduled basis. In general, the larger hydropower plants with a high degree of flexibility are called on to provide the highest levels of AGC. Since the Lower Snake dams have some operating constraints such as the requirement to stay within one foot of minimum operating pool, BPA does not rely heavily on these plants for AGC and operating reserves. It was assumed, based on historic AGC scheduling, that the Lower Snake plants provide AGC at a level of about 30 MW, spread over all four plants. Generally, the AGC is called on from these plants only during the heavier load periods in which AGC from the larger, more flexible plants is reaching their maximum amounts. It was judged that AGC is provided from the Lower Snake River plants about 20 percent of the time. BPA estimates that the current value of this AGC support ranges from $5.00 to $16.50 per MW based on recent monthly market values. The annual value lost from removing the four dams was computed as $465,000 as shown in Table 31.

Table 31
Automatic Generation Control Losses

Month	Hours Per Month	MW Provided	Percent of Time	Value (1998 Real $)	Monthly Value
Jan	744	30	20%	$9.50	$42,408
Feb	672	30	20%	9.50	38,304
Mar	744	30	20%	8.50	37,944
Apr	720	30	20%	5.00	21,600
May	744	30	20%	5.00	22,300
Jun	720	30	20%	6.50	28,080
Jul	744	30	20%	9.50	42,408
Aug	744	30	20%	16.50	73,656
Sep	720	30	20%	11.50	49,680
Oct	744	30	20%	6.50	29,016
Nov	720	30	20%	8.50	36,720
Dec	744	30	20%	9.50	42,408
Annual (Rounded)	8760	30	20%		$465,000

5.6.2 Reserves. The four Lower Snake River dams are also used to provide part of the required reserves for the Federal power system. The WSCC has established reserve requirements for all utilities. These contingency reserves are expected to be "on-call" in the event of emergency loss of generating resources in the system. Utilities are required to have both operating and spinning reserves. The spinning reserve units must be synchronized with the power system and provide immediate response, while the operating reserves must be available within 10 minutes. Similar to the scheduling of AGC, BPA defines which plants in the system will provide reserves at what time of the year. The larger, more flexible, hydropower plants are called on to provide the biggest share of reserves over much of the year. The Lower

Snake River plants, which have less flexibility, are called on less often to provide system reserves. BPA estimates, based on historic dispatch, that the Snake River plants are used for reserves for about one half of the months of December and March, and all of the months of January, February, April, May, and June. BPA relies on about 300 MW of reserves from these four plants in these time periods.

The market values of these reserve services vary throughout the year. In the high demand winter months, during cold snaps BPA has had to purchase energy to free up capacity at Federal hydropower plants to provide necessary reserves. These purchases have a market value of $31/MW-month and were estimated to be required about 25 percent of the time during the last half of December, January, and February. During the remaining 75 percent of this period and the balance of the year the average monthly market price for reserves was used in this analysis. Table 32 shows how the lost reserves from the four plants were computed using these assumptions. The annual net economic cost associated with the loss of these reserves is estimated to be $7,183,000.

Table 32
Lost Annual Reserve Values

Month	Heavy Load Hours	MW Provided	Purchase % of Time	Market Sale & of Time	Purchase Cost (1988 Real $)	Market Value (1998 Real $)	Monthly Value
Dec 1/2	248	300	25%	75%	$31.00	$8.00	$1,023,000
Jan	496	300	25%	75%	$31.00	$8.00	$2,046,000
Feb	448	300	25%	75%	$31.00	$8.00	$1,848,000
Mar 1/2	248	300	0%	100%	$31.00	$7.00	$520,800
Apr	480	300	0%	100%	$31.00	$3.50	$504,000
May	496	300	0%	100%	$31.00	$3.50	$520,800
Jun	480	300	0%	100%	$31.00	$5.00	$720,000
Annual (Rounded)	2,648	300					$7,183,000

5.6.3 Other Ancillary Services. The Lower Snake projects do provide additional reactive power support to the intra- and inter-regional transmission lines. The economic value of this service is accounted for in section 5.5, *System Transmission Impacts*.

5.6.4 Summary of Ancillary Services. This section provides an estimation of the loss in ancillary services that will occur with alternative A3. It was assumed that this estimate is an annual value that will occur for each year that the Lower Snake River Dams are out of service. It was also assumed that this same value would be lost with alternative A5. There may be some gains in ancillary services with alternatives

A2 and A6, but these were judged to be relatively small and were not quantified. The ancillary loses with removal of John Day Dam are expected to be large, but these were not quantified for this study. The value of the ancillary services was based on the current operation of the system. If additional operating constraints are imposed on the larger, Columbia River, hydropower plants over time, their ancillary service benefits will be restricted and projects like the four Lower Snake dams may provide a higher level of these types of benefits.

The total ancillary annual losses for A3 and A5 are the combination of the AGC loss ($465,000) in Table 31 and the loss of reserve value ($7,183,000) in Table 32. The total loss is $7,648,000, annually. This was rounded to $8 million for reporting purposes in the rest of this document.

5.7 ALTERNATIVE-SPECIFIC EFFECTS

This section addresses the hydropower effects that are associated with a couple of the alternatives. These impact areas were identified late in the study process and hence were not incorporated in the hydro-regulation and power system modeling. The analyses presented in this section should be considered preliminary. At the time of printing this study many of the key assumptions concerning these impacts had not been finalized. For this reason, the results presented in this section are provided for general information only and are not included in the total hydropower economic effects summaries.

5.7.1 Reduction of Irrigation Withdrawals With Alternatives A3 and A5. It was originally assumed throughout the DREW evaluation of alternatives A3 and A5 that with the breaching of the Lower Snake Dams the irrigation withdrawals from the Snake River would continue at a higher cost. It was discovered in the water supply studies that the costs of providing irrigation water to the 37,000 acres that currently withdraw from the Snake River reservoirs were prohibitively high. Hence, it was assumed in the water supply studies that these 37,000 acres would go out of production. This will have two impacts on hydropower production. There will be less consumption of electricity to pump water from the Snake River up to the cropland. There will be more water in the Lower Columbia because the crops on the 37,000 acres will no longer consume about 2.24 Acre-Feet (AF) of water per acre (ac).

Available information was used and several simplifying assumptions were made to do this hydropower evaluation. The best estimate of annual pumping energy used to irrigate this acreage is about 82,000 MWh per year. To simplify the analysis, it was assumed that the irrigation pumping occurred uniformly over the period of March through September. The crop consumption of 2.24 AF/ac for 37,000 ac resulted in removing about 83,000 AF of water that could have been used for generation at the downstream dams of McNary, John Day, The Dalles, and Bonneville. With alternatives A3 and A5, it was assumed that water would be available at a uniform amount over the period of March through September. This equated to an additional constant flow of about 200 cfs over this time period. This additional flow was translated into additional energy generation at the four Lower Columbia River dams based on the kW/cfs relationships for each month of the 60 simulated water years.

Table 33 shows the average monthly gains in downstream generation and the reduced energy consumption due to irrigation pumping. These energy amounts were added to HYSSR results on a monthly basis for alternatives A3 and A5 to be used in the market-pricing model described in section 5.3. The average annual increase in hydropower values associated with the loss in irrigated land was estimated at about $2.3 million with the three discount rates.

Table 33
Average Energy Gain A3 and A5
With Reduced Irrigation

Month	Irrigation Gain (aMW)	Pumping Energy (aMW)	Total Energy Gain (aMW)
Oct			
Nov			
Dec			
Jan			
Feb			
Mar	4.31	16.00	20.31
Apr	3.92	16.00	19.92
May	3.87	16.00	19.87
Jun	3.94	16.00	19.94
Jul	4.25	16.00	20.25
Aug	4.32	16.00	20.32
Sep	4.47	16.00	20.47
Average	**2.42**	**9.33**	**11.76**

5.7.2 Alternative A2 At-Site Generation. The A2 alternative evaluated in this technical report was modeled based on certain assumptions of hydropower generation at the four Lower Snake dams. Throughout the study process different configurations of project improvements have been investigated for the A2 alternative and numerous A2 options are still being considered. The purpose of this subsection is to evaluate a couple A2 options to examine the possible range of impacts on at-site hydropower production at these four dams.

The A2 alternative evaluated in this report assumed that spill for passing juvenile salmon and steelhead would be eliminated at the three Lower Snake projects that fish barging occurs. That is, it was assumed that no fish spill would occur at Lower Granite, Little Goose, and Lower Monumental. As shown in this report, the A2 alternative had a higher level of hydropower generation than the base condition, and it has net economic benefits (*i.e.*, negative net costs) for hydropower of about $10 million per year with the medium economic forecast.

The A2 options investigated in this subsection consider the impact of including Surface Bypass Collectors (SBC) at some of the Lower Snake projects. The SBC will require additional flow to be diverted away from the power units to move the collected juvenile salmon and steelhead. It is estimated that flows as high as 6,000 cfs may be required to operate the SBC. Since this flow will not be passing through the hydropower units, less hydropower generation will occur than was assumed in the original analysis for the A2 alternative. Two options are investigated here, (1) Option 1, SBC at Lower Granite with flow diversions of 6,000 cfs during the fish migration period of April through October, and (2) Option 2, SBC at Lower Granite, Little Goose, and Lower Monumental with flow diversions of 6,000 cfs at each project.

A simplified study approach was taken to analyze the two options to alternative A2. The HYSSR model results were used to define generation with each option. The kW/cfs relationships at each project for the original A2 evaluation were used to define generation for each month of the 60 water years. Table 34 shows the average generation loss from the original A2 alternative with the two options for SBC.

Table 34
Average Energy Loss From A2
With SBC Options

Month	SBC at Lower Granite (aMW)	SBC at Lower Granite, Little Goose, Lower Monumental (aMW)
Oct	40.4	121.2
Nov	--	--
Dec	--	--
Jan	--	--
Feb	--	--
Mar	--	--
Apr	38.9	115.7
May	33.7	98.9
Jun	33.1	99.3
Jul	40.8	122.1
Aug	40.7	121.9
Sep	40.4	120.9
Average	22.33	66.67

To estimate the economic effects associated with these reductions in generation the pricing model was used. The generation amounts in each month and water year were subtracted from the original A2 data, and the pricing model was run to determine the change in power benefits from the base condition. This economic evaluation was done only for the medium economic forecast condition. Table 35 summarizes the results. With the SBC at only the Lower Granite project (option 1) the average annual net costs compared to the base condition (A1), are about -$4.5 million as compared to about -$9.6 million with the original A2 alternative. This means that with the A2 alternative and a SBC at Lower Granite there would be an additional $4.5 million per year hydropower benefit compared to the base condition. With a SBC at Lower Granite (LWG), Little Goose (LGS), and Lower Monumental (LMN) (option 2) the average annual net costs compared to the based condition would be about $3.8 million. This means that inclusion of SBC at three projects, with a 6,000 cfs flow diversion requirement at each of these projects, the hydropower benefits would be reduced about $3.8 million annually from the base condition. This is approximately a $13.2 million reduction in annual power benefits from the original A2 alternative. These general results were consistent over the three discount rates.

Table 35
Average Annual Net Costs With SBC
Examination of SBC Options for A2
($ 1998 Millions)

Discount Rate	Original A2 A1	A2 With SBC At LWG -- A1	Difference From Original A2 A1	A2 With SBC at LWG, LGS and LMN A1	Difference From Original A2 A1
6.875%	-9.6	-5.1	-4.5	3.8	13.2
4.75%	-9.6	-5.1	-4.5	3.9	13.3
0%	-9.4	-5.0	-4.4	4.0	13.4

The final designs and selection of the best A2 options had not been done at the time of completion of this technical report. So, the A2 options presented in this section are likely to change and it was decided not to include these options elsewhere in this document. The examination presented here is meant to demonstrate the relative magnitude of impacts associated with some potential fish bypass measures at the Lower Snake dams.

5.8 SUMMARY OF NET ECONOMIC EFFECTS

This section combines all the net economic effects as defined by the medium projection conditions. These represent the most likely estimates of economic effects. However, because of the uncertainty embedded into many of the key variables, a risk and uncertainty analysis was undertaken to provide a range of results. See section 6.0 for a complete presentation of the uncertainty and variability associated with these estimates. Table 36 presents the medium results for the two key approaches used to identify the net increases in costs to the power system as compared to the base condition. The costs in the table are the average annual equivalents with different discount rates. The two approaches used in the study were the system production costs and the market pricing approach. Two separate models were used to define the system production costs: the BPA model and the PROSYM model. The market price approach used the market clearing prices projected by the NPPC with the Aurora model, and the results of two hydro-regulation models: HYDROSIM and HYSSR. Different estimates of net economic costs were made by each of these approaches and models. But, the range of results from minimum to maximum is relatively small. The range is also relatively small over the three discount rates. For example, the annual net costs for the A3 alternative at 6.875% is from $221 to $255 million. While, the results for A3 range from $217 to $260 million over all three discount rates.

Table 36
Summary of System Costs (Production Costs and Market Prices)
Cost Differences From Alternative A1
Medium Projections, 1998 $ Million, Average of All Water Conditions
Various In-Service Dates, 100-Year Analysis

Alternatives	Procuction Costs	Market Price		Range of Costs	
	BPA Model	HYDROSIM	HYSSR	Minimum	Maximum
Discount Rate 6.875%					
A2	-9	-7	-10	-10	-7
A3	255	221	225	221	255
A5	251	204	212	204	251
A6a	-21	-17	-21	-21	-17
A6b	-1	0	-3	-3	0
B1	504	438	433	433	504
B2			405	405	405
C1	386	331	328	328	386
C2			294	294	294

Discount Rate 4.75%					
A2	-9	-7	-10	-10	-7
A3	256	220	224	220	256
A5	253	203	211	203	253
A6a	-21	-17	-21	-21	-17
A6b	-1	0	-3	-3	0
B1	506	436	432	432	506
B2			403	403	403
C1	387	330	326	326	387
C2			293	293	293
Discount Rate 0%					
A2	-9	-7	-9	-9	-7
A3	260	217	221	217	260
A5	256	199	208	199	256
A6a	-22	-17	-21	-22	-17
A6b	-1	0	-3	-3	0
B1	510	433	430	430	510
B2			400	400	400
C1	390	327	324	324	390
C2			291	291	291

The costs shown in Table 36 do not include the costs that would be incurred to maintain the same degree of reliability in the transmission system and the values for loss of ancillary services. As shown in Tables 28 to 30, BPA will have to build additional facilities at an average annual cost of $21.9 to $28.1 million (at 6.875%), $19.4 to $24.2 million (at 4.75%), and $15.6 to $17.9 million (at 0.0%). The ancillary services lost with alternatives A3 and A5 were estimated in section 5.6 as $8 million per year.

Table 37 presents the range of effects with the medium forecast conditions based on the combination of system costs in Table 36, the ancillary services costs, and the transmission-related costs shown in Tables 28 to 30. It is the study teams recommendation that these net economic costs represent the most likely effects associated with each alternative.

Table 37
Total Average Annual Net Economic Effects
Differences From Alternative A1
Medium Projections, 1998 $ Million, Average of All Water Conditions
Various In-Service Dates, 100-Year Analysis

Alternatives	System Costs		Transmission Reliability Costs		Ancillary Services Costs	Total Effects	
	Minimum	Maximum	Minimum	Maximum		Minimum	Maximum
Discount Rate 6.875%							
A2	($10)	($7)	(0	$0	$0	($10)	($7)
A3	221	255	22	28	8	251	291
A5	204	251	22	28	8	234	267
A6a	(21)	(17)	0	0	0	(21)	(17)
A6b	(3)	(0)	0	0	0	(3)	(0)
B1	433	504	NA	NA	NA	NA	NA
B2	405	405	NA	NA	NA	NA	NA
C1	328	386	NA	NA	NA	NA	NA
C2	294	294	NA	NA	NA	NA	NA
Discount Rate 4.75%							
A2	($10)	($7)	$0	$0	$0	($10)	($7)
A3	220	256	19	24	8	247	288
A5	203	253	19	24	8	230	285
A6a	21	(17)	0	0	0	(21)	(17)
A6b	3	(0)	0	0	0	(3)	(0)
B1	432	506	NA	NA	NA	NA	NA
B2	403	403	NA	NA	NA	NA	NA
C1	326	387	NA	NA	NA	NA	NA
C2	293	293	NA	NA	NA	NA	NA
Discount Rate 0%							
A2	($9)	($7)	$0	$0	$0	($9)	($7)
A3	217	260	16	18	8	241	286
A5	199	256	16	18	8	223	282
A6a	(22)	(17)	0	0	0	(22)	(17)
A6b	(3)	(0)	0	0	0	(3)	(0)
B1	430	510	NA	NA	NA	NA	NA
B2	400	400	NA	NA	NA	NA	NA
C1	324	390	NA	NA	NA	NA	NA
C2	291	291	NA	NA	NA	NA	NA

6.0 RISK AND UNCERTAINTY ANALYSIS

The uncertainty surrounding the estimates of hydropower economic effects can be categorized into two major areas of water availability and economic forecast. This section summarizes the significance of uncertainty in these two categories.

The generation of hydropower from the Lower Snake River projects can vary widely from year to year, and month to month, based on water availability. (See Technical Exhibit A at the end of this report). The estimation of net economic costs in this report by the two methods of market-clearing prices and system production costs were developed over the range of possible water conditions. The two hydro-regulation models, HYSSR and HYDROSIM, simulated water conditions for water years from 1928 to 1988, and 1928 to 1978, respectively. Both models provided monthly generation in each of the simulated years over the 50 or 60 water conditions, and these PNW hydropower generation estimates served as the major input to the economic models.

The study team identified the economic factors that they felt would most influence the estimation of net economic effects. To account for the uncertainty embedded in projections of these factors into the future, the study team identified a range of projections for three conditions: high, medium and low. The variables that were handled with a range of estimates were fuel prices, load projections for the different electrical demand regions, and the technology efficiency gains of new combined cycle combustion turbine power plants. Most of the results presented in this report were based on the medium projections which the study team felt best reflected the most likely future condition.

The following discusses the possible range of net economic effects as defined by the market-clearing price approach. The market-clearing approach was used here because it did not require numerous computer model runs, and the results are similar to what the BPA or PROSYM models would provide. No attempt was made to estimate uncertainty ranges for the transmission reliability costs and the ancillary benefits. These latter two economic effects were developed as point estimates with relatively cursory analyses. It must be recognized that a high degree of uncertainty exists in these two cost categories, but that the magnitude of the costs is small compared to the other power cost categories, and therefore it is probably acceptable to use just point estimates for them.

Table 38 presents the range of net economic costs based on the different economic forecast conditions of high, medium, and low, and the 50 different water year conditions. The data in the table is based on the differences from the base condition of alternative A1. The low projection condition included the low projection of each of the variables of fuel prices, loads, and technology. That is, the examination did not mix between high, medium, and low conditions of each of the individual key variables. Each water year simulation was modeled with each of the different economic conditions.

Table 38
Uncertainty Ranges
HYDROSIM - Pricing Model Results for 2010
Annual Net Economic Costs (1998 $ Million)

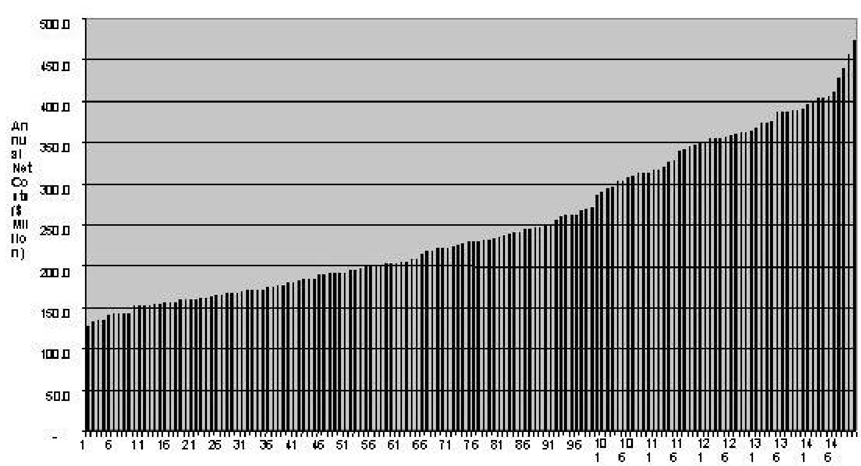
Year	A2			A3			A5		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Average	**(6.3)**	**(7.4)**	**(12.8)**	**(166.3**	**228.1**	**357.2**	**160.7**	**215.1**	**343.9**
Minimum	**(10.5)**	**(12.4)**	**(22.1)**	**126.7**	**155.8**	**246.1**	**109.4**	**143.4**	**234.2**
Maximum	**(0.1)**	**(0.1)**	**(0.2)**	**221.6**	**302.2**	**473.4**	**217.8**	**300.3**	**474.6**
Stand Dev	**2.5**	**2.9**	**5.0**	**20.5**	**31.9**	**47.0**	**22.6**	**22.6**	**46.9**
1929	(10.4)	(11.8)	(21.1)	159.1	218.6	362.8	154.0	201.6	344.0
1930	(5.1)	(5.8)	(11.1)	153.4	202.7	326.4	139.9	177.4	302.9
1931	(5.2)	(6.1)	(11.3)	133.8	179.8	288.9	131.1	170.2	284.1
1932	(10.0)	(12.1)	(22.1)	142.5	195.6	309.3	138.5	188.7	303.4
1933	(5.4)	(6.6)	(10.9)	133.4	209.3	328.0	136.5	185.8	293.3
1934	(5.7)	(6.8)	(12.0)	141.4	155.8	246.1	123.0	157.9	258.2
1935	(0.1)	(0.1)	(0.2)	126.7	159.7	250.1	109.4	143.4	234.2
1936	(5.0)	(6.2)	(11.5)	142.4	203.6	319.9	137.3	183.5	299.0
1937	(8.4)	(9.5)	(17.1)	135.0	208.9	339.8	140.3	184.2	306.2
1938	(9.9)	(11.5)	(19.8)	152.5	200.3	312.6	139.6	188.3	303.3
1939	(8.0)	(9.2)	(16.3)	152.3	232.4	372.9	161.2	212.8	356.5
1940	(8.6)	(9.9)	(17.7)	163.8	221.1	354.1	161.9	213.6	357.6
1941	(4.2)	(4.8)	(9.5)	160.6	239.4	389.3	159.5	209.9	348.9
1942	(8.0)	(9.6)	(16.3)	161.4	199.8	315.3	142.2	189.6	311.4
1943	(7.1)	(7.9)	(14.4)	191.2	302.2	473.4	217.8	300.3	474.6
1944	(4.3)	(5.7)	(10.6)	166.2	218.7	356.7	160.9	206.0	348.5
1945	(8.9)	(10.2)	(17.9)	160.1	191.0	312.1	141.7	192.3	322.6
1946	(6.9)	(8.5)	(13.4)	169.6	240.6	373.5	168.1	228.4	365.6
1947	(7.9)	(9.2)	(15.7)	204.5	267.3	410.3	188.2	254.4	400.6
1948	(2.5)	(3.3)	(4.8)	184.1	270.0	406.0	148.9	250.7	377.9
1949	(5.2)	(6.5)	(9.8)	183.4	234.4	367.6	176.0	235.2	374.0
1950	(10.5)	(12.4)	(20.5)	164.9	229.9	353.1	157.9	211.8	326.7
1951	(9.4)	(11.1)	(18.2)	174.9	241.0	375.8	184.0	251.0	401.2
1952	(4.0)	(4.8)	(9.4)	190.4	249.2	386.9	172.5	233.8	368.4
1953	(8.5)	(9.9)	(16.8)	168.8	244.4	385.9	162.4	219.9	351.3
1954	(8.5)	(10.2)	(16.8)	155.8	230.7	346.9	151.5	206.5	309.8
1955	(7.1)	(7.9)	(14.6)	141.9	190.2	303.1	146.2	193.7	311.2
1956	(4.1)	(4.8)	(8.3)	176.5	228.1	348.1	167.1	221.9	339.8
1957	(7.7)	(9.5)	(15.4)	179.0	246.8	385.8	169.5	228.6	363.9
1958	(6.6)	(7.9)	(13.5)	169.7	229.4	357.3	161.1	215.2	339.4
1959	(6.0)	(6.7)	(12.2)	166.3	236.0	361.4	164.0	219.3	343.1
1960	(7.6)	(8.9)	(15.0)	166.1	227.1	349.9	160.0	217.3	341.3
1961	(4.4)	(5.0)	(9.1)	139.6	200.0	307.7	139.6	186.3	297.5
1962	(8.8)	(10.3)	(17.7)	152.7	214.4	341.0	149.9	203.6	333.9
1963	(7.3)	(8.2)	(15.2)	170.4	221.9	345.0	155.5	209.3	335.5
1964	(7.7)	(9.2)	(14.5)	156.2	258.6	403.9	186.9	254.4	399.5
1965	(4.4)	(5.2)	(8.3)	221.6	296.0	457.3	211.9	286.1	447.2
1966	(0.2)	(0.2)	(0.3)	158.2	202.9	316.9	137.9	181.4	293.9
1967	(7.9)	(9.1)	(15.8)	151.6	203.1	312.9	141.4	189.0	297.7
1968	(3.3)	(3.8)	(7.0)	163.3	224.5	353.7	165.3	226.9	365.4
1969	(5.6)	(6.9)	(10.5)	190.8	261.7	395.3	179.2	243.7	375.2
1970	(7.5)	(8.5)	(14.6)	176.8	244.0	387.3	167.2	223.9	360.6
1971	(3.2)	(3.8)	(6.0)	197.5	286.6	440.2	199.3	266.3	411.7
1972	(2.3)	(3.0)	(4.4)	189.3	262.2	397.2	182.2	244.8	374.3
1973	(4.6)	(5.3)	(10.2)	170.7	223.3	360.0	169.6	218.2	359.9
1974	(2.9)	(3.5)	(5.4)	195.4	261.8	404.3	178.8	240.7	374.4
1975	(5.9)	(6.9)	(11.0)	183.1	269.4	427.3	194.9	268.2	427.9
1976	(7.9)	(9.4)	(16.1)	198.5	255.0	388.4	177.1	233.8	357.1
1977	(5.2)	(6.0)	(11.0)	152.2	181.2	292.8	124.1	159.5	267.2
1978	(8.8)	(9.8)	(18.2)	175.2	231.9	362.2	165.2	224.2	352.7

Reading horizontally across the top of Table 38 indicates the effect of varying the economic projections from the low to high conditions. For example, the net economic costs for alternative A3, based on the average of all 50 water conditions, range from a low of $166 million to a high of $357 million. This is a variation of $191 million per year. This represents a percentage change of 115% from the low to high condition. The percentage change from low to high conditions is generally the same for all of the alternatives of A2, A3, and A5.

Reading vertically shows the effects of different water conditions on the economic costs, when the economic forecasts are not varied. For example, with the medium economic forecast conditions for A3, the net economic costs range from a minimum of $156 million to a maximum of $302 million. This is a variation of $146 million per year. This is a percentage change of 94% from the lowest to highest water conditions. This same general trend holds for the A5 alternative. The impacts of water conditions on the A2 alternative are significant on a percentage change basis, but the variation in annual economic costs is from about $-0.1 to $-22 million depending on the low to high economic forecast. The A2 alternative will have economic benefits when compared to the base condition of alternative A1 (hence the negative net costs). This alternative appears to be the alternative most significantly influenced by water year conditions based on the percentage change from low to high water years. For example, in water years of 1935 and 1966 the economic costs/benefits are virtually the same as the base condition ($-0.1 million for medium forecast), up to $-12.4 million in water year 1950.

To demonstrate the overall variance in net economic costs, the results of all simulations for each alternative were compared. For example, Figure 20 shows the range of net economic costs for A3 when all water year simulations and the three economic forecasts are considered. The net economic costs range from a low of $127 million to a high of $473 million. The ranges of values for A5 were $109 million to $475 million, and for A2 the range was $ -0.1 million to $ -22 million.

Figure 20
Net Costs (Market Price Approach) - Alternative A3 With Low, Medium, High Forecasts and 50 Water Years



These ranges of uncertainty must be considered by the decision-makers in their selection of the preferred plan. The Economic Appendix of Feasibility Study will consider the uncertainties in this hydropower analysis with the uncertainties in all the other economic categories.

One question raised in the study process was whether the removal of the four Lower Snake River dams would result in a larger variability in system production costs on a water year-by-water year basis or across future economic conditions than with the existing system. If the region experiences a larger degree of variability with the removal of the Snake River dams, then utilities could be forced to provide for some level of insurance against this increased variability.

To answer this question the study team examined the total West Coast system production costs as defined by the BPA model. Table 39 shows the system production costs for year 2010 by water year for alternatives A1 and A3 under the medium forecast conditions. Table 39 also shows the system production costs for the average water year and the three economic conditions. The highlighted cells show the range between the lowest and highest values across water years and economic forecasts. The ranges of results over the water years for the medium forecast for alternative A3 ($1,515 million) is somewhat less than the range with alternative A1 ($1,609 million). This is because alternative A3 has approximately 1,225 aMW less hydropower generation, but it has more capacity and generation from combined-cycle combustion turbines (CC). The increased numbers of CC plants tend to reduce the annual variation in system production costs due to water that is experienced by a system with more hydropower generation. However, the range of system production costs for average water under the three economic forecasts is larger for A3 ($5,825 million) than for A1 ($5,705 million). This is because the forecasts for natural gas prices vary significantly from the Low forecast condition to the High forecast condition. This wide variability in natural gas prices is reflected more with the A3 alternative because it has a larger amount of natural gas-burning CC plants.

Table 39 Total West Coast Production Costs Costs by Water Year (1998 $ Millions), With 3 Economic Forecasts Year 2010								
	Alternative A1				**Alternative A3**			
	Low	**Medium**	**High**	**Range**	**Low**	**Medium**	**High**	**Range**
Average	$2,021	$4,335	$7.725	$5,705	$2,210	$4,582	$8,036	$5,825
Stand Dev.		$452				$418		
Minimum		$3,610				$3,911		
Maximum		$5,219				$5,426		
Range		$1,609				$1,515		

Water Year	Low	Medium	High		Low	Medium	High	
1929		$4,966				$5,167		
1930		5,125				5,327		
1931		5,169				5,341		
1932		4,642				4,853		
1933		4,260				4,470		
1934		3,839				4,058		
1935		4,547				4,732		
1936		4,796				4,995		
1937		5,098				5,275		
1938		4,394				4,617		
1939		4,804				5,011		
1940		4,755				4,966		
1941		5,219				5,426		
1942		4,558				4,791		
1943		4,131				4,422		
1944		5,163				5,393		
1945		5,028				5,242		
1946		4,276				4,524		
1947		4,077				4,406		
1948		3,934				4,216		
1949		4,211				4,481		
1950		4,173				4,423		
1951		3,668				3,964		
1952		3,970				4,271		
1953		4,373				4,621		
1954		4,001				4,240		
1955		4,166				4,381		
1956		3,610				3,911		
1957		4,145				4,414		
1958		4,408				4,662		
1959		3,976				4,249		
1960		3,853				4,114		
1961		4,264				4,476		
1962		4,475				4,721		
1963		4,285				4,541		
1964		4,296				4,534		
1965		3,723				4,081		
1966		4,350				4,587		
1967		4,202				4,431		
1968		4,215				4,463		
1969		3,807				4,103		
1970		4,448				4,712		
1971		3,920				4,237		
1972		3,622				3,912		
1973		4,624				4,849		
1974		3,826				4,108		
1975		4,036				4,317		
1976		3,746				4,090		
1977		5,068				5,233		
1978		4,498				4,753		

The difference in variability of system production costs between A1 and A3 over water conditions and economic forecasts is relatively small on a percentage basis. Therefore, the study team decided that no adjustments in insurance measures would be needed by utilities if the Snake River dams were removed.

7.0 FINANCIAL ANALYSIS

This section examines the possible financial impacts to PNW ratepayers if alternative A3 is implemented. The other alternatives were not examined because all cost information was not available at the time of this analysis.

It is not possible to say for sure how the economic costs to the power system that have been estimated in this report will ultimately be paid. Before the restructuring of the electricity industry, it would have been easier to guess at how the financial effects might have been distributed. A large portion of the costs would have been BPA's responsibility and BPA would have increased its rates to recover the increased costs. As a result, the customers who buy BPA power would see higher electricity prices. Customers would react to this financial impact by adjusting their consumption of electricity and other goods and services. These reactions would reduce the purchase of BPA electricity by an amount that depends on what economists call the elasticity of demand. As consumers reduce their consumption of electricity, BPA would have to further raise prices to recover the same revenue and cover its costs. The end result of this adjustment process would depend on how much cost BPA could avoid when its sales decrease and how responsive consumers are to price changes. But in any case, the financial impacts would fall primarily on the consumers that buy BPA-supplied electricity.

In a restructured, competitive, wholesale power market, BPA can no longer automatically recover higher costs by raising its rates. This is because the utilities that buy power from BPA have alternative supplies of electricity available at prices set by the wholesale electricity market. If BPA's prices are below the market price, it may be able to recover increased costs until its prices reach the market price.

However, consumers of BPA power are no longer required to bear the financial impacts of increased hydroelectric costs if less expensive electricity is available in the market. In this case, the financial impacts will be more difficult to determine. Initially, the cost would appear as BPA losses, but those losses would have to be covered by someone such as taxpayers or users of the still-regulated transmission system.

It is not the intent of this section to determine where the financial impacts of the hydroelectric costs will fall. The intent is to illustrate the magnitude of the costs in terms that may be more meaningful to readers by providing some examples of effects on consumers under different assumptions. For example, an illustration of the effect of spreading the cost over all BPA customers does not imply that this is possible, likely, or a good idea. It is just a way to place the economic costs on a consumer financial impact basis to illustrate relative magnitudes of effect.

This section examines results only at the discount rate of 6.875%. The current (Fiscal Year 1999) interest rate that BPA repays hydropower debt is 6.0%. The 6.875% discount rate is the closest of the three study discount rates to the current hydropower repayment rate, and therefore is the only one used in this financial section.

Sections 7.1 and 7.2 describe the economic costs that will be paid by someone if alternative A3 is implemented. Section 7.3 explores the range of PNW ratepayers that could be impacted. Section 7.4 shows the extent of rate impacts with the wide range of possible financial impacts. Section 7.5 briefly discusses the influence that demand elasticity could have on the results presented in section 7.4. Section 7.6 summarizes the financial analysis and restates the purpose of this analysis.

7.1 IMPLEMENTATION COST RECOVERY

A specific question associated with the issue of who would pay for hydropower related losses is; who would pay for the costs of implementing the alternatives such as breaching of the four Lower Snake River Dams? Two possible scenarios are presented here: (1) BPA will repay hydropower’s share of the implementation costs; and (2) the nation’s taxpayers will pay the costs.

Congress will ultimately answer the repayment question in the legislation that would authorize the implementation of the selected alternative. The Congressional authorization could contain directive language concerning the allocation of project construction costs. For example, Congress could direct that removal of the Snake River Dams is of national interest and the taxpayers' responsibility, and BPA would not have to repay any of the construction costs.

The Feasibility Report and EIS will examine this cost allocation issue, and will present a range of possible allocation scenarios. With the traditional Corps of Engineers cost allocation approach the implementation costs would be considered as mitigation actions which are considered joint-use costs. The costs would be allocated based on the existing joint-use percentages. Hydropower would repay about 90 percent of the costs (through BPA repayment to the Treasury) and navigation would be allocated about 10 percent (Federal costs). This has been the approach for past fish and wildlife measures at all Columbia and Snake River dams.

The other scenario examined here is the assumption that all implementation costs will be borne by the U.S. taxpayers.

Another important point concerning the implementation costs is that the costs should be net of costs that would occur if alternative A3 were not implemented. Without the breaching of the four Snake River dams, considerable investments will have to be made over time to maintain and repair the dams. The Technical Report for Implementation Costs provides the detailed construction costs, interest costs, O&M, and assumed replacement and repair over the 100 year period of analysis. Table 40 includes data from the Implementation Technical report. The table demonstrates how the average annual costs of alternatives A1 and A3 compare and to what extent BPA’s repayment costs will change under different scenarios. The top part of this table shows the scenario in which BPA would repay 90 percent of the net implementation costs. This is the traditional Corps of Engineer’s cost allocation approach and it is applied here to the situation in which the PNW region would be responsible for the implementation costs. This table shows that with the 6.875% discount rate and BPA required to pay 90% of the costs for both A3 and A1, that

BPA would have $19.6 million more annual repayment costs with A3 than A1. The bottom portion of Table 40 shows the net BPA costs if no repayment were required from BPA for the dam breaching, and BPA would be required to continue to pay 90 percent of the costs for these projects with alternative A1. With these assumptions, BPA would have an annual repayment saving of about $71.3 million at 6.875%. This is because under this scenario the dams would be removed with A3 and BPA would have no further costs. However, if A1 were the future condition, BPA would have to pay for the O&M, R, R.

Table 40
Implementation Cost Stream for Alternatives
Alternatives A1 and A3
Preliminary Subject to Change
1998 $ Millions

	Annual Implementation Costs at 6.875%
With BPA (Or PNW) Paying 90% of Implementation Costs of A3	
Average Annual Costs of A3	$101.00
Average Annual Costs of A1	$79.20
Net Average Annual Costs	$21.80
Hydropower's Share	90%
Hydropower's Net Annual Costs	$19.60
With BPA (Or PNW) Not Repaying Implementation Costs of A3	
Average Annual Cost of A3 Without Repay	$0.00
Average Annual Cost of A1 (Assuming 90% BPA)	$71.30
BPA Net Annual Costs With A3	($71.30)

7.2 POWER COSTS

This technical report has identified the economic costs associated with the changes in hydropower generation from the four Lower Snake River plants. Table 41 summarizes these annual economic costs for Alternative A3 based on the three economic conditions of Low, Medium, and High, and the three discount rates. These are the average annual equivalent amounts based on the system production cost approach.

Table 41
Summary of Annual Economic Costs
For Alternative A3[1]
Based on Differences From Alternative A1
($ 1998 Million) (6.875%)

Effect	Economic Conditions		
	Low	Medium	High
System Prod Cost[1] Ancillary Services[2] Transmission Impacts[3]	$187 $8 $25	$255 $8 $25	$329 $8 $25
Total	**$220**	**$288**	**$362**

[1]System production costs taken from Table 21.
[2]Ancillary service costs summarized in section 5.6.4.
[3]Transmission impacts presented in section 5.5.

7.3 POSSIBLE AFFECTED RATEPAYERS

The question examined here is over which ratepayers, or load, could the economic and implementation costs be spread? As discussed above there is no certainty as to which ratepayers will be impacted by these additional costs. The following are just examples of different impact distributions. To simplify the analysis, only one load year of year 2010 was examined. The approach presented here looks at several possibilities:

Load 1, the entire PNW load. The PNW regional load for year 2010 is projected to be 25,457 aMW, or 223,003,320 MWh, based on the load growth assumptions used in this report.

Load 2, consumers who have benefited from federal power. These are the regional consumers who have benefited from Federal hydroelectric power, either through direct purchases from the BPA, or through a mechanism called the regional exchange. This would exclude the commercial and industrial customers of regional investor-owned utilities. These customers constitute about 30 percent of the total regional load. The remaining load for year 2010 is projected to be 17,820 aMW, or 156,103,200 MWh, based on the load growth assumptions used in this report.

Load 3 and 4, BPA load. The costs of changes in hydro-system operations have traditionally been borne only by the customers of BPA, rather than by all the electricity consumers in the PNW. This tradition has come into question since the advent of electricity price deregulation and the development of an active wholesale market in the trading of electricity. Since BPA's customers are no longer captive, and are free to buy power from other suppliers, BPA will only sell its electricity if its price is below the average market price. Hence the price BPA can charge is effectively capped by the market price of electricity.

So what is the effect on BPA's customers and the region's other customers from policies that allocate changes in hydro-system costs only to BPA? There are two possibilities examined here: allocating costs over all BPA sales (load 3); or allocating costs over only BPA's firm, cost-based sales (load 4). BPA sales under average water conditions are approximately 10,540 aMW or 92,330,000 MWh per year. However, loss of the Lower Snake plants would reduce this generation by about 1,250 aMW under average water. With the removal of the Snake River Dams the annual BPA sales would be about 9,290 aMW or 81,380,000 MWh. BPA firm sales are approximately 8,200 aMW or 71,832,000 MWh. Loss of the Lower Snake plants would reduce BPA firm sales by about 760 aMW under critical water, so BPA firm sales would be about 7,440 aMW or 65,174,000 MWh.

7.4 POSSIBLE RATE IMPACTS

Table 42 presents the possible power rate increases based on the various loads, repayment scenarios, additional power system costs, and the 6.875 % discount rate. This table shows the impacts associated with the dam breaching alternative (A3), based on a mills per kilowatt basis. Figures 21 and 22 graphically presents the range of possible rate impacts using the 6.875% discount rate and the two scenarios that hydropower will be responsible to repay 90% of the implementation costs and no repayment for alternative A3, respectively.

Table 42
Financial Analysis of Hydropower Costs With 6.875% Discount Rate
Alternative A3 Differences From Alternative A1 ($ 1998)

With A3 Implementation Costs Allocated to Hydropower			
	Low	**Medium**	**High**
Implementation Costs 90% to Hydro	$19,620,000	$19,620,000	$19,620,000
System Power Costs	$220,000,000	$288,000,000	$362,000,000
Total Economic Costs	$239,620,000	$307,620,000	$381,620,000
Annual Costs/PNW Load of 223,003 GWh (mills/kWh)	1.07	1.38	1.71
Annual Costs/Federal Beneficiaries Load of 156,103 GWh (mills/kWh)	1.54	1.97	2.44
Annual Costs/BPA Sales of 81,380 GWh - for A3 & A5 (mills/kWh)	2.94	3.78	4.69
Annual Costs/BPA Firm Sales of 65,174 GWh - for A3 & A5 (mills/kWh)	3.68	4.72	5.86
With No A3 Implementation Costs Allocated to Hydropower			
	Low	**Medium**	**High**
Implementation Costs 90% to Hydro	($71,280,000)	($71,280,000)	($71,280,000)
System Power Costs	$220,000,000	$288,000,000	$362,000,000
Total Economic Costs	$148,720,000	$216,720,000	$290,720,000
Annual Costs/PNW Load of 223,003 GWh (mills/kWh)	0.67	0.97	1.30
Annual Costs/Federal Beneficiaries Load of 156,103 GWh (mills/kWh)	0.95	1.39	1.86
Annual Costs/BPA Sales of 81,380 GWh - for A3 & A5 (mills/kWh)	1.83	2.66	3.57
Annual Costs/BPA Firm Sales of 65,174 GWh - for A3 & A5 (mills/kWh)	2.28	3.33	4.46

FIGURE 21 Financial Impacts @ 6.875% - Alternative A3 (Assuming Hydropower Will Repay 90% of Implementation Costs)

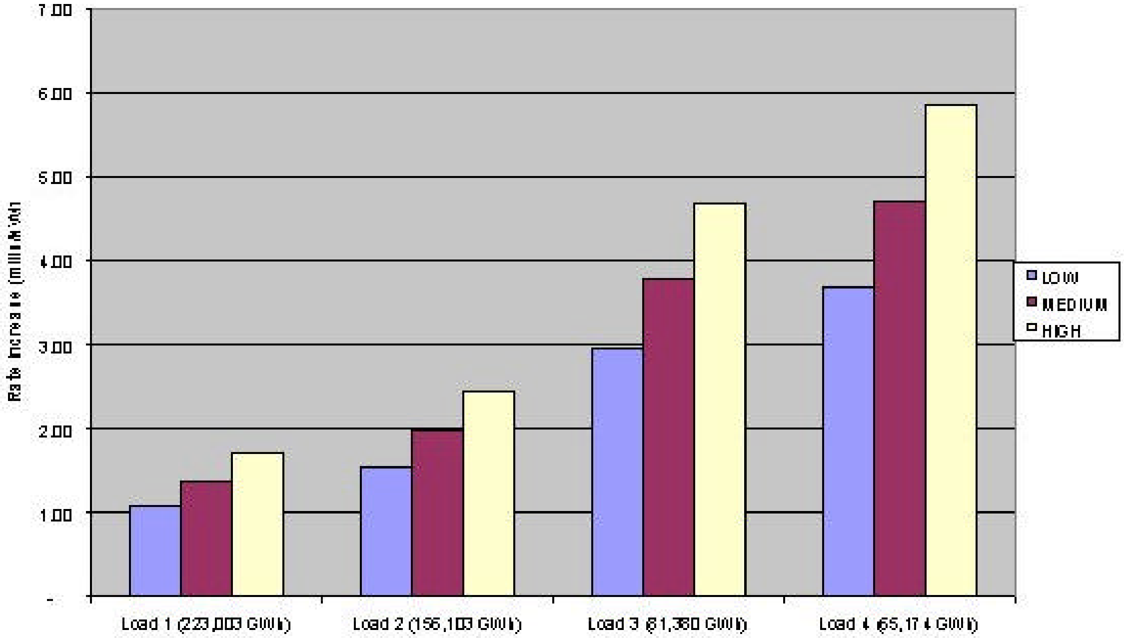
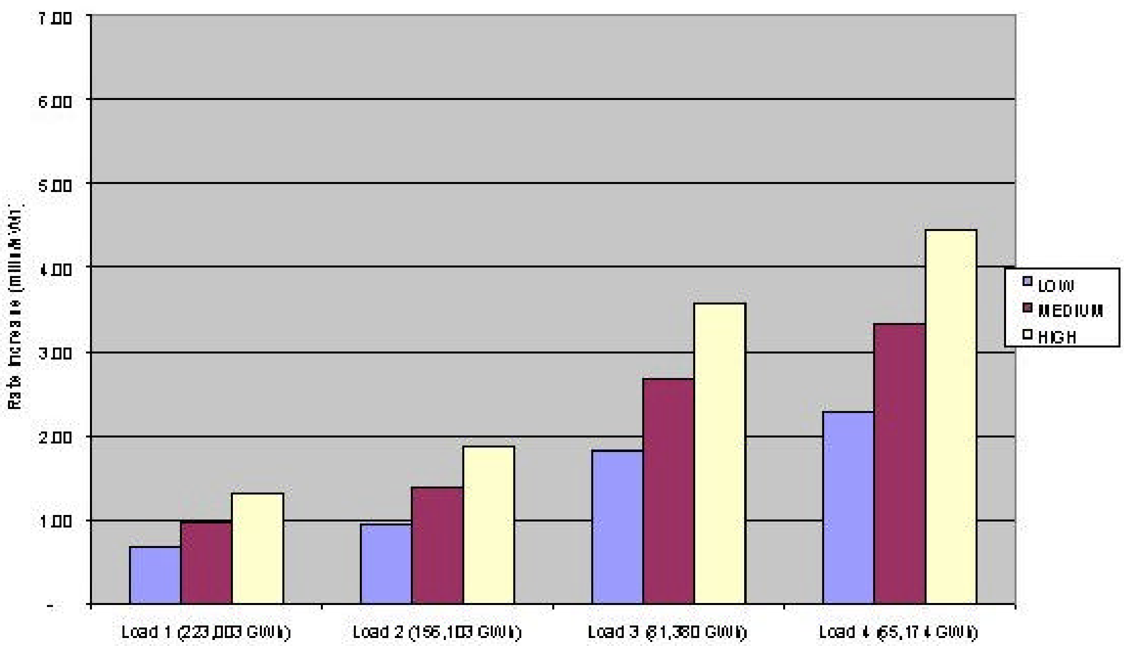


FIGURE 22 Financial Impacts @ 6.875% - Alternative A3 (Assuming No Hydropower Repayment For A3)



With the numerous scenarios presented here, it can be seen that the possible average wholesale rate increases to power customers could be as low as 0.67 mills/kWh and as high as 5.86 mills/kWh. How these increased wholesale rates would translate to increases in monthly power bills to the different power consumers is very hard to determine. Each power utility purchases different amounts of BPA's wholesale electricity to serve its residential, commercial, agricultural, and industrial customers. Some PNW utilities purchase almost no power from BPA, and hence the rate increases would be very minimal to their customers. However, other utilities rely exclusively on purchases from BPA, and these potential rate increases could be passed directly to their customers.

To demonstrate the possible extent of rate increases to different customer sectors, some typical monthly electricity consumption data were compiled. Table 43 shows some typical average monthly electricity use based on actual 1995 consumption as compiled by the NPPC. The sector data is provided based on whether the customers were served by a public utility or a private utility. The table also provides consumption data for typical commercial or public buildings.

Table 43
Examples of Average Monthly Electricity Consumption

Sector	Public Utility (kWh/Month)	Private Utility (kWh/Month)	Average of Public and Private (kwh/Month)
Residential	1,195	1,031	1,113
Commercial	6,451	5,947	6,199
Industrial (Non-DIS)	392,901	168,795	280,848
Aluminum Plant (220 aMW)	160,600,000		160,600,000
Commercial/Public Examples			
Grocery Store			120,000
Elementary School			27,000
Hospital			927,000
Hotel			400,000
Large Office Building (408,000 sq ft)			581,000

Table 44 combines the average rate increases shown in Table 42 with the typical consumption data presented in table 43. This table shows the average monthly electricity bill increase assuming that the wholesale rate increases would be directly passed on to the different consumer sectors. This will not happen in all utilities, but is presented for illustrative purposes. This table is based on the 6.875% discount rate, and assumes that hydropower will repay 90% of the implementation costs.

Table 44
Possible Monthly Bill Increases by Sector
Based on 6.875% and Hydropower 90% Cost Allocation

		Rate Increase (mills/kWh)		
		Low	**Medium**	**High**
	Load 1	**1.07**	**1.38**	**1.71**
	Load 2	**1.54**	**1.97**	**2.44**
	Load 3	**2.94**	**3.78**	**4.69**
	Load 4	**3.68**	**4.72**	**5.86**
Sector	**Consumption (kWh/Month)**	**($/Month) Low**	**($/Month) Medium**	**($/Month) High**
Load 1:				
Residential	1,113	$1.2	1.5	1.9
Commercial	6,199	6.7	8.6	10.6
Industrial (Non-DSI)	280,848	301.8	387.4	480.6
Aluminum Plant	160,600,000	172,567.1	221,538.6	274,831.2
Load 2:				
Residential	1,113	$1.7	$2.2	$2.7
Commercial	6,199	9.5	12.2	15.2
Industrial (Non-DSI)	280,848	431.1	553.4	686.6
Aluminum Plant	160,600,000	246,522.9	316,481.9	392,613.7
Load 3:				
Residential	1,113	$3.3	$4.2	$5.2
Commercial	6,199	18.3	23.4	29.1
Industrial (Non-DSI)	280,848	826.9	1,061.6	1,317.0
Aluminum Plant	160,600,000	472,880.0	$607,075.1	753,111.0

Load 4:				
Residential	1,113	$4.1	$5.3	$6.5
Commercial	6,199	22.8	29.3	36.3
Industrial (Non-DSI)	280,848	1,032.6	1,325.6	1,644.5
Aluminum Plant	160,600,000	590,465.1	758,028.8	940,377.6

As can be seen in Table 44 the average PNW household monthly electricity bill could increase between $1.20 and $6.50 depending on which set of cost distribution and economic forecast assumptions is applied. The monthly bill impact for the average PNW commercial establishment could increase between $6.70 and $36.30. The impacts for the larger commercial and public facilities are discussed below.

The major impact would be to the industrial sector if the assumed cost distributions occur. For example, the average industrial customer (excluding the aluminum companies and other Direct Service Industries) could see monthly electricity bills increase between $302 and $1,645. The aluminum companies in the PNW are extremely large consumers of electricity, and this is reflected in the average monthly consumption of 160,600,000 kWh. Clearly, any increase in the electricity rate will have a significant impact on the monthly power bills. Depending on the selection of cost distribution and economic condition impacts, the average monthly power bill for aluminum companies could increase between $172,600 and $940,400.

Table 45 shows the monthly bill increase estimates for some selected business and public buildings. The previous table was averaged over all commercial and industrial business, while Table 45 shows possible cost increases for commercial and public buildings.

Table 45
Possible Monthly Bill Increases
Example Commercial and Public
Based on 6.875% and Hydropower 90% Cost Allocation

		Rate Increase (mills/kWh)		
		Low	**Medium**	**High**
	Load 1	**1.07**	**1.38**	**1.71**
	Load 2	**1.54**	**1.97**	**2.44**
	Load 3	**2.94**	**3.78**	**4.69**
	Load 4	**3.68**	**4.72**	**5.86**
Sector	**Consumption (kWh/Month)**	**($/Month)**	**($/Month)**	**($/Month)**
		Low	**Medium**	**High**
Load 1:				
Grocery Store	120,000	$128.9	$165.5	$205.4
Elementary School	27,000	29.0	37.2	46.2
Hospital	927,000	996.1	1,278.7	1,586.4
Hotel	400,000	429.8	551.8	684.5
Large Office Building	581,000	624.3	801.5	994.3
Load 2:				
Grocery Store	120,000	$184.2	$236.5	$293.4
Elementary School	27,000	41.4	53.2	66.0
Hospital	927,000	1,423.0	1,826.8	2,266.2
Hotel	400,000	614.0	788.2	977.9
Large Office Building	581,000	891.8	1,144.9	1,420.4
Load 3:				
Grocery Store	120,000	$353.3	$453.6	562.7
Elementary School	27,000	79.5	102.1	126.6
Hospital	927,000	2,729.5	3,504.1	4,347.0
Hotel	400,000	1,177.8	1,512.0	1,875.7
Large Office Building	581,000		2,196.2	2,724.5

Load 4:				
Grocery Store	120,000	$441.2	$566.4	702.6
Elementary School	27,000	99.3	127.4	158.1
Hospital	927,000	3,408.2	4,375.4	5,428.0
Hotel	400,000	1,470.6	1,888.0	2,342.2
Large Office Building	581,000	2,136.1	2,742.3	3,402.0

7.5 ELASTICITY OF DEMAND

The sections above presented a large range of possible rate impacts using the simplified assumption that PNW and PSW power demand would not change with the higher rates. Based on simple demand theory as power rates increase, consumers will react to those increases, often by purchasing less electricity. As consumers purchase less electricity, power system demand goes down, and hence not as much electricity is needed. Depending on the magnitude of the reaction by consumers to the rate increase, not as many resources may be needed after a rate increase.

This is the notion of elasticity in demand -- changes in the quantity of a good purchased based on changes in its price. The elasticity is defined as a ratio of the percentage change in quantity demanded to the percentage change in price. Trying to incorporate the concept of elasticity of demand for electricity into this rate impact discussion is complicated by the fact that BPA might be responsible for recovering many of the economic costs presented here. So, if BPA sells less electricity at the higher rate, it will be forced to raise rates even higher to recover the fixed costs. Demand elasticity would then again reduce the quantity consumed, and the rate adjustment cycle would occur again. This iterative process was modeled on a simplified basis in the Columbia River System Operation Review, Final

Environmental Statement, November 1995 (SOR). In the SOR study the price elasticity was assumed to be -0.4 for power utilities. A spreadsheet model was used to repeat the iterative price and demand adjustments. The results of including the price elasticity process resulted in about a 10 percent reduction in total economic costs associated with hydropower effects.

A large degree of uncertainty is associated with possible market adjustments to the increased power costs, the possible distribution of impacts to regional ratepayers, and the appropriate magnitude of the demand elasticity. For these reasons, the study team decided to not apply the demand elasticity approach to the economic effects identified in this study. It is appropriate to note that the amount of electricity demanded will probably be less if demand elasticity is considered. The impact on the average ratepayer is not expected to be significantly different if the demand elasticity were incorporated.

7.6 FINANCIAL ANALYSIS SUMMARY

The examination above is intended to illustrate the magnitude of the costs in terms that may be more meaningful to readers. This section provides some examples of effects on consumers under a wide range of possible future conditions. It is not possible at this time to say how the economic costs to the power system that have been estimated in this report will ultimately be paid.

Regardless of what set of assumptions is made the key financial question for BPA is will the electric power market price support these increases in power rates? If not, some other mechanism will need to be found to pay for changes in operating costs associated with changes in hydro system operations. Some such mechanisms are discussed in the NPPC report (See Technical Exhibit B) on BPA financial feasibility. Such mechanisms could include a surcharge on the transmission system, a regional tax on the use of electricity, monetary support for such changes from the U.S. taxpayer, etc. If the market will support these increases in rates, then the findings presented here have a higher probability of occurring to regional ratepayers.

8.0 MITIGATION ANALYSIS

8.1 POSSIBLE MITIGATION

The steps undertaken in this mitigation analysis were to: (1) examine the economic effects estimated for changes in hydropower production to determine who will be impacted, (2) list potential measures that will serve to mitigate or reduce the impacts, (3) evaluate the potential measures for economic or socially acceptable feasibility, and (4) recommend measures for considerations.

The economic impacts presented above will be widely distributed in varying degrees amongst the electric ratepayers throughout the WSCC region. However, the PNW region will be the most impacted based on the regional system production costs shown in this analysis. As discussed in section 7 above, it is expected that the power rate impacts to each individual electric ratepayer will fall within a wide range of possibilities. Exactly to what extent these rate increases will occur is impossible to determine at this time.

No possible mitigation measures were identified. To mitigate for the increased power system costs some alternative way of meeting power demands (loads) would need to be identified. The analyses in this report identified the most cost-effective way to meet power loads with each of the alternatives. Any possible mitigation plan would be more costly and hence not mitigate the impacts, but only change them to some other mix of power resources.

8.2 COMPENSATION POTENTIAL

The economic effects could be compensated by subsidizing each ratepayer an amount equivalent to their impact. This could come from the nation's taxpayers to the regional ratepayers. This would require congressional authorization. This compensation would constitute a transfer of the economic effects from one region of the country to the entire country.

9.0 SUMMARY

This technical report concentrated on the identification of the net economic effects associated with changes in hydropower production from the Lower Snake River Dams. To identify the economic effects different approaches were taken and a range of study assumptions were evaluated. This section only briefly presents the various study approaches and provides reference to pertinent portions of the report for more detailed descriptions.

9.1 NET ECONOMIC EFFECTS SUMMARY

The Executive Summary at the beginning of this report provides a summary of the economic effects of each alternative. The following directs the reader to the appropriate section of the report for each major study component.

The basic study approach was to establish an oversight team of interested individuals (the Hydropower Impact Team -- HIT) to review and guide the analyses being conducted primarily by the staffs of the Bonneville Power Administration (BPA) and the Corps of Engineers (Corps). To examine the economic effects from a wide range of viewpoints several different models and study assumptions were utilized.

Two separate, but similar, system hydro-regulation models were used to estimate the amount of hydropower generation that would occur in the Columbia River basin with the different alternatives of this study (See section 3.0). It was found that the results from the two hydro-regulation models were not significantly different.

Three system power models were used to identify the net economic costs associated with the change in hydropower generation (see section 4.0). The three power models are all proprietary models that have been used by the Corps, BPA, and the Northwest Power Planning Council (NPPC) in other studies. The three models were similar but varied in scope. All the models identified which power resources would be operated to meet expected loads in the future. The BPA Regional Power Spreadsheet Model (BPA model) and the PROSYM model used by the Corps identified the production costs associated with meeting loads throughout the year. The Aurora model used by the NPPC presented the marginal cost of the last power resource used to meet load in each time period. With these different models two basic approaches were used to identify the net economic costs. The BPA and PROSYM models identified the system production costs associated with meeting load in the PNW and California, and the total WSCC, respectively. Aurora identified the market-clearing prices in the WSCC based on the marginal cost at each time period. The results from the BPA and Aurora models served as the primary estimate of net economic effects, and the PROSYM model was used primarily to confirm results from the other models and test numerous study assumptions. The net economic effects computed from the three models were surprisingly close.

One major question in this analysis was how many new generating resources would be constructed to replace the lost capacity associated with breaching the Lower Snake River dams. The amount of this replacement capacity would influence the generation reliability in the PNW and constitutes a major element of the net economic costs. The BPA and Aurora models estimated how much new capacity would be built based on economic optimization routines which selected the level of new capacity that minimized the total system production costs (system variable costs + fixed costs of new capacity). The report examined different levels of new capacity in section 5.4. It was found that the total system production costs did not vary significantly with different levels of new capacity. This occurred because the variable production costs tended to reduce with construction of new efficient combined cycle combustion turbine, gas-driven power plants. The reduction in variable costs somewhat offset the increase in fixed costs with the addition of new capacity.

The basic study of economic effects was conducted assuming that the reliability of the region's electricity transmission would not change with the different alternatives. However, if the four Lower Snake River dams are breached the transmission system will be impacted. Section 5.5 identifies the transmission-related costs that will be necessary to maintain the transmission system's ability to move bulk power and serve regional loads. The costs to maintain the transmission system reliability with each alternative were added to the other economic effects.

A range of different water conditions and different economic forecast conditions were examined in the study. Section 4.3 presents the various key economic assumptions and section 6.0 discussed the effect that uncertainty has on the results. Section 7.8 contains the results of all the net economic studies. Tables 37 and ES-1 provide the summary of net economic effects by discount rates and economic forecast conditions, respectively.

9.2 OTHER STUDY COMPONENTS

The study team conducted examinations of other impacts that were not included in the net economic effects. The Drawdown Regional Economic Workgroup (DREW) defined which economic impacts should be included as net economic effects in all the impact areas such as hydropower, navigation, recreation, etc. This oversight by DREW resulted in theoretically consistent estimates of net economic effects in all the technical reports associated with the different impact areas. DREW requested that the following elements be examined and reported in this hydropower report, but these were not to be included in the net economic effects. These study elements consisted of a cursory examination of rate impacts (section 7.0), possible mitigation measures (section 8.0), and the estimation of changes in air pollutant emissions with different alternatives (section 4.4).

TECHNICAL EXHIBITS

TECHNICAL EXHIBIT A. HYDRO-REGULATION MODELING RESULTS

The following are the HYSSR results for the system hydropower generation with each of the study alternatives.

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A1

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	9234	9256	9719	12377	11468	10478	10782	11117	14884	14454	9586	11730	11261
1930	8474	8443	9855	11009	7310	9481	8508	12770	16034	16081	9656	9678	10609
1931	8460	8405	9724	10855	7162	7997	8015	11340	16366	14755	9741	9438	10190
1932	8501	8398	9650	10133	10749	9959	13084	15606	17305	19262	14984	9672	12277
1933	9103	9236	10224	14685	19673	17637	12531	13338	15931	21894	20046	10607	14579
1934	11030	12149	13977	19860	24719	18755	18854	24613	22596	16313	10035	15624	17375
1935	8580	8265	9282	12631	18226	14845	11330	11500	17450	17935	14595	9826	12873
1936	9034	8592	9725	11648	13576	10805	10344	14473	20096	17414	9829	11716	12278
1937	8407	8391	9828	11223	11027	9961	8148	10660	14700	15060	9538	10334	10610
1938	8416	8254	9298	11336	17401	14390	13461	15674	21301	17938	13189	9668	13362
1939	8620	8844	9485	11826	12120	9801	10528	15556	18888	16397	9543	9947	11798
1940	8453	8762	9705	12014	10804	11877	13004	15753	15907	16231	9688	10847	11925
1941	8456	8525	9578	11217	11806	11010	11001	13509	15210	13478	7950	9734	10957
1942	8403	8289	9483	16393	18070	13651	9511	13856	15508	15958	11960	8208	12442
1943	8739	8677	9231	13704	19437	17436	12867	21189	19430	19988	15708	9910	14695
1944	8618	8910	9460	11929	11384	10281	10640	12282	15114	11519	7900	13017	10926
1945	8462	8381	9578	11233	9646	9251	7526	8971	14760	15910	12762	8782	10439
1946	8303	8457	9432	12728	17927	15584	14112	17206	21721	19298	14020	10693	14128
1947	9171	9261	10375	18244	19620	18602	16630	15476	19537	18654	13225	11073	14994
1948	9016	14303	12784	15429	19431	18718	15800	16306	23224	25715	14917	10670	16363
1949	10827	9466	10053	12806	14935	14409	14654	17425	21025	18513	11799	15884	14314
1950	8364	8310	9579	14781	19552	18596	17315	16844	19544	23223	18811	10061	15417
1951	9613	11836	1333	19564	19282	19251	18164	21886	23889	18894	15954	15329	17248
1952	9765	13226	10960	15713	19656	16702	11774	18599	23112	18260	12666	14341	15399
1953	8283	8333	9633	11404	19272	17882	12432	12154	17421	20047	16347	10955	13685
1954	8874	9250	10572	14795	19376	18428	17340	15710	20273	22570	17413	12261	15576
1955	15769	10391	11994	14868	18692	14197	9795	12885	14747	18571	19573	16753	14854
1956	8931	11267	12882	19361	19331	18648	18142	21907	25284	24723	16513	14588	17632
1957	9194	10207	9826	15182	19313	15612	14186	14247	23205	21716	11693	14816	14935
1958	8289	8478	9448	12154	18958	17363	12124	14888	22399	18084	10072	10847	13566
1959	8380	9347	11304	16883	19661	18656	18279	18408	17861	22167	17803	10917	15810
1960	14622	15982	14563	17509	19843	16182	14153	18799	16667	18201	14744	14352	16304
1961	8988	9300	11018	13341	19642	18272	18000	16115	18297	23063	13511	12079	15143
1962	8564	9428	9709	12701	17596	15009	10741	17045	17580	17356	13298	11090	13348
1963	8810	9990	12137	16711	18059	17501	11278	14610	16842	16044	12303	10808	13761
1964	9453	8963	9816	13104	19468	15975	11620	12925	14778	24387	17968	10406	14075
1965	10254	11239	10936	19274	19287	18502	18168	20651	20931	20592	14850	14948	16637
1966	9797	10217	10536	14193	19293	12769	10624	16472	16939	17478	13256	15312	13907
1967	8829	8936	9670	14443	19406	18634	15997	11866	17125	24409	16380	11025	14732
1968	9123	10211	10723	14435	19533	18201	14170	13064	16636	17023	15071	14861	14422
1969	12158	12137	12574	15922	19443	18751	17782	20232	22951	19573	14560	12294	16535
1970	8644	9335	9715	13273	17954	15735	11141	12416	16151	17181	13367	10932	12992
1971	8389	8671	9264	14076	19260	18427	18234	21155	24653	25005	17294	10970	16288
1972	10071	9228	9943	13930	19283	18269	24853	21106	23594	26756	18745	15468	17604
1973	11362	9587	9571	15095	13429	10748	11121	12279	15087	16110	9616	16626	12552
1974	8423	8255	9098	13421	23012	20438	20348	23549	23614	26319	21257	9118	17240
1975	11041	8858	9496	13098	19327	16020	13324	11944	18611	21584	19366	16361	14918
1976	10001	10912	13040	19572	20344	18567	18248	20389	22896	19655	17834	13223	17060
1977	16428	9159	9572	12263	11788	10345	10837	12061	15093	10897	7352	17152	11914
1978	8496	8320	9200	10648	14531	12647	14277	17038	18079	17113	14822	9375	12881
1979	11023	9080	9657	12457	10817	12524	12911	13832	17503	17062	9673	10668	12271
1980	8412	8356	9603	11013	16438	14416	10914	14479	21183	16981	10741	10442	12752
1981	8390	8716	9501	18262	19742	18687	16380	13668	18062	18229	15432	9929	14585
1982	8988	9010	10528	14724	19565	18292	18945	19573	19769	24030	18542	14327	16360
1983	11507	10580	10172	15606	19304	18473	18007	18897	19058	17348	17617	15125	15975
1984	9516	9017	13251	15348	19288	18021	16793	16625	16051	20597	17559	13826	15494
1985	9813	8984	10541	13903	15529	11600	10417	16803	18962	16731	9772	12205	12945
1986	8327	9464	10923	13524	19532	18355	17913	19157	17008	17072	11691	9683	14389
1987	8284	8897	10325	13469	10639	11739	12888	14863	19328	16365	9693	9917	12203
1988	8486	8464	9810	10987	7098	8704	8275	13050	15914	15914	9695	9728	10484
Average	9466	9520	10414	14071	16800	15200	13820	15846	18729	18834	13725	11997	14038

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A2

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	9234	9256	9719	12377	11468	10478	10782	11191	14887	14794	9585	11812	11303
1930	8481	8438	9854	11013	7476	9481	8508	12862	16234	16120	9664	9678	10652
1931	8458	8415	9727	10961	7165	8000	8015	11420	16597	14953	9741	9624	10258
1932	8501	8398	9650	10155	10749	9970	13077	15837	17593	19660	14984	9680	12356
1933	9103	9236	10224	14685	19664	17648	12531	13421	16190	22438	20046	10607	14653
1934	11030	12149	13977	19860	24719	18755	18854	24760	22596	16319	10039	15624	17388
1935	8589	8259	9295	12910	18236	14846	11331	11584	17711	18216	14595	9817	12950
1936	9034	8592	9726	11648	13576	10805	10344	14478	20598	17696	9829	11716	12344
1937	8411	8391	9823	11216	11028	9961	8168	10741	15163	15289	9546	10330	10675
1938	8427	8254	9301	11414	17401	14390	13461	15674	21879	18506	13203	9665	13466
1939	8620	8844	9485	11826	12120	9801	10528	15653	19329	16648	9543	9947	11864
1940	8449	8875	9722	12147	10804	11875	13004	15992	16451	16222	9700	10849	12012
1941	8453	8534	9570	11239	11809	11010	11001	13599	15217	13909	7995	9734	11007
1942	8403	8289	9483	16393	18070	13651	9511	14130	16013	15957	12292	8224	12536
1943	8775	8687	9420	13785	19432	17487	12882	21186	19869	20407	15708	9918	14798
1944	8618	8910	9460	11929	11384	10281	10640	12363	15122	11984	7899	13017	10972
1945	8462	8381	9578	11233	9646	9215	7526	9033	15446	15921	13173	8780	10536
1946	8299	8634	9434	12680	17930	15588	14149	17341	22233	19496	14020	10735	14216
1947	9171	9261	10375	18244	19620	18602	16630	15777	19933	19092	13225	11073	15089
1948	9016	14303	12784	15429	19431	18718	15800	16391	23377	25726	14917	10670	16384
1949	10827	9466	10053	12806	14935	14409	14654	17518	21399	18650	11805	15884	14365
1950	8369	8548	9596	14562	19552	18596	17314	17245	19964	23640	18811	10058	15524
1951	9613	11836	13323	19564	19282	19251	18164	22272	24310	19271	15954	15329	17347
1952	9765	13226	10960	15713	19656	16702	11774	18783	23089	18805	12666	14341	15458
1953	8283	8333	9633	11404	19272	17882	12432	12379	17978	20433	16347	10955	13783
1954	8874	9250	10572	14795	19376	18428	17340	15976	20699	22570	17413	12261	15634
1955	15769	10391	11994	14868	18692	14197	9795	12971	14739	19368	19625	16753	14932
1956	8944	11302	12882	19361	19331	18648	18142	22144	25242	25114	16518	14603	17687
1957	9194	10207	9826	15182	19313	15612	14186	14624	23155	22144	11693	14816	14998
1958	8295	8575	9448	12258	18957	17363	12123	15178	22405	18471	10072	10487	13640
1959	8380	9347	11304	16883	19661	18656	18279	18433	18243	22606	17803	10917	15881
1960	14622	15982	14563	17509	19843	16182	14153	18934	17177	18620	14744	14352	16392
1961	8988	9300	11018	13341	19642	18272	18000	16200	18698	23352	13511	12079	15208
1962	8564	9428	9709	12701	17596	15009	10741	17041	18055	18049	13299	11090	13445
1963	8810	9990	12137	16711	18059	17501	11278	14702	17337	16616	12412	10808	13867
1964	9457	8964	9838	13104	19468	15975	11620	13157	15377	24505	17997	10403	14159
1965	10254	11239	10936	19274	19287	18502	18168	20829	21343	20697	14850	14948	16695
1966	9797	10217	10536	14193	19293	12769	10624	16577	17188	17739	13256	15312	13958
1967	8829	8936	9670	14443	19406	18634	15997	11939	17667	24775	16399	11024	14815
1968	9123	10211	10723	14435	19533	18201	14170	13149	16865	17505	15071	14861	14488
1969	12158	12137	12574	15922	19443	18751	17782	20590	23365	19652	14561	12294	16606
1970	8644	9335	9715	13273	17954	15735	11141	12498	16761	17586	13367	10932	13083
1971	8394	8695	9258	14051	19260	18425	18236	21536	24596	24959	17292	10970	16311
1972	10071	9228	9943	13930	19283	18269	24851	21231	23959	26748	18750	15468	17644
1973	11362	9587	9571	15095	13429	10748	11121	12364	15095	16113	9606	16624	12559
1974	8423	8254	9096	13559	23015	20439	20350	23890	23634	26722	21266	9483	17346
1975	11041	8858	9496	13098	19327	16020	13324	12180	19014	21591	19366	16361	14972
1976	10001	10912	13040	19572	20344	18567	18248	20795	23021	20067	17829	13223	17138
1977	16445	9159	9572	12263	11788	10345	10837	12147	15112	11333	7357	17152	11961
1978	8496	8320	9200	10648	14531	12647	14277	17224	18527	17679	14836	9373	12982
1979	11023	9080	9657	12457	10817	12624	12865	13893	18030	17324	9672	10651	12345
1980	8410	8356	9605	11009	16438	14416	10914	14479	21657	17441	10772	10441	12832
1981	8391	8796	9501	18261	19741	18687	16329	13758	18467	18623	15432	9932	14662
1982	8988	9010	10528	14724	19565	18292	18945	19674	20275	24275	18535	14327	16431
1983	11507	10580	10172	15606	19304	18473	18007	18880	19678	17813	17617	15125	16064
1984	9516	9017	13251	15348	19288	18021	16793	16961	16394	20635	17559	13826	15554
1985	9813	8984	10541	13903	15529	11600	10417	17174	19281	16985	9767	12205	13023
1986	8334	9468	10923	13524	19532	18355	17913	19551	17543	17609	11691	9681	14512
1987	8284	8897	10325	13469	10639	11739	12888	14956	19385	17017	9701	9917	12270
1988	8486	8465	9814	10762	7094	8702	8273	13141	15779	15915	9695	9727	10489
Average	9467	9533	10418	14078	16803	15203	13820	16006	19049	19139	13743	12008	14108

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A3

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8645	8631	9580	11682	10887	9974	9845	9826	12613	12350	8648	11123	10321
1930	8282	8326	9333	9627	6806	8901	7477	11185	13916	13954	9674	9040	9710
1931	8384	8325	9015	9794	6989	7037	7195	10011	14529	13484	9385	8900	9423
1932	8446	8404	8979	9190	10572	9753	10542	13429	14895	17244	13787	9198	11204
1933	8592	8679	9638	14062	19664	15954	11367	11562	14327	19108	18729	10022	13478
1934	10522	11609	13483	19837	22219	18758	18378	20613	20791	15232	9947	14770	16344
1935	8586	8266	9296	10845	17359	13953	10544	10178	15327	16271	14386	9807	12070
1936	8509	8357	9718	11279	12603	9867	9267	11743	17510	15775	9483	11116	11274
1937	8410	8392	9832	10741	8555	9036	7195	9624	12948	13382	8802	9668	9717
1938	8413	8248	9301	10771	15809	12456	12038	13471	18732	15925	12447	9311	12244
1939	8371	8294	9479	10947	10666	9134	8789	13474	16651	15239	8018	9648	10727
1940	8451	8315	9720	11032	9658	10372	11495	13759	14107	14650	9315	10621	10962
1941	8453	8341	9576	10874	9236	9872	9654	12132	13178	11757	7204	8993	9939
1942	8405	8198	9489	13511	17229	12885	8844	11785	13487	14186	11576	7615	11435
1943	8418	8360	9230	11079	18225	15042	10771	18034	16829	17403	13907	9313	13053
1944	8308	8176	9451	11026	10820	9814	9229	10822	12824	9564	7137	12001	9936
1945	8468	8378	8948	9926	9559	8390	7032	7119	12798	13567	11172	8223	9468
1946	8303	8258	9323	10712	16460	13905	12159	14777	19158	17392	13285	10221	12832
1947	8371	8185	9554	16614	19617	17523	13038	13300	16569	16983	12013	10518	13527
1948	8368	13212	12122	14441	19430	18025	11854	13945	19844	22455	13680	10216	14801
1949	10202	8819	9584	12068	14063	13286	12477	15027	17825	16379	11016	14912	12969
1950	8365	8149	9439	12513	19413	16678	14792	14027	17363	20603	17321	9621	14025
1951	8897	10946	12582	18146	19293	18287	16637	16275	21294	17290	14753	14327	15726
1952	9140	12373	10481	14545	18428	15185	10301	15413	19719	16410	11511	13376	13908
1953	8273	8255	9647	11150	16340	15030	11287	10411	15310	17211	14896	10443	12358
1954	8258	8637	10146	14033	19368	18420	13308	13322	18084	20536	16213	11307	14307
1955	15150	9788	11615	14175	17821	13490	9430	11162	12763	16341	18385	15784	13827
1956	8380	10532	12316	17733	19282	18153	14300	18424	21606	21884	15281	13658	15963
1957	8544	9452	9361	14194	18422	14166	12371	11855	19822	19346	10528	13847	13494
1958	8283	8170	9458	10704	17644	14898	10899	12780	18997	15992	9514	10007	12281
1959	8298	8161	10293	15300	19324	18614	14656	15157	15583	20155	16787	10211	14381
1960	13836	14880	13832	16467	19195	14832	12564	16386	14648	16295	14533	13598	15091
1961	8363	8529	10355	12550	19656	18278	15117	13717	16330	2142	12629	11122	13989
1962	8419	8300	9390	11830	16773	13972	9727	14653	15284	15880	12133	10665	12256
1963	8372	8971	11218	15584	17265	15921	10277	12825	14730	14247	11802	10072	12610
1964	8482	8314	9246	12314	19005	13798	10552	10701	12898	20915	16514	9900	12722
1965	9536	10548	10486	17351	19269	18513	12799	16025	17865	17442	13357	13942	14762
1966	8903	9346	10058	13182	18267	12097	9574	14654	14830	15972	12467	14189	12795
1967	8425	8270	9407	13321	19419	18631	12828	10428	14843	21469	15184	10717	13583
1968	8537	9449	10173	13531	18891	16375	12878	11810	14866	15425	13972	13957	13323
1969	11391	11090	11520	14808	19441	17184	13587	17610	19949	17756	13446	11282	14925
1970	8380	8162	9488	12313	16306	14353	9977	10743	14104	14470	12097	10450	11740
1971	8385	8195	9262	10814	19269	18430	12623	16502	20909	21595	15655	10347	14336
1972	9083	8457	9530	12897	19283	18271	17953	18593	20503	23232	17642	14482	15827
1973	10607	8772	9440	13703	12249	10038	10178	11052	13175	14408	8910	15661	11515
1974	8175	8252	8634	10885	20541	18545	17971	20203	20796	23040	19668	8616	15447
1975	10346	8262	9498	11796	18290	14482	11569	9989	16175	18239	17454	15314	13450
1976	9094	9989	12418	18963	19227	18562	14831	15392	19227	17635	16737	12136	15354
1977	15651	8439	9573	11199	11008	9919	10103	11104	13424	9611	6897	16094	11086
1978	8502	8312	8486	10060	12508	10750	12664	14751	15839	15359	13446	8921	11635
1979	9821	8375	9558	11422	10686	10890	11342	12005	15203	15503	9261	10082	11182
1980	8410	8357	9609	10812	14264	11957	9901	12834	18891	15090	9706	9564	11618
1981	8388	8392	9493	14926	19744	18007	12441	12044	16069	16123	14333	9277	13273
1982	8473	8409	10103	13841	19550	18289	15503	14286	16284	21046	16584	13559	14663
1983	10568	9690	9686	14379	19126	16525	15553	14450	16424	14996	16070	14093	14297
1984	8625	8218	12419	14074	18294	15188	14255	13916	13157	17077	15982	12730	13665
1985	8815	8145	9830	12755	14318	10719	9439	14256	16810	15071	9426	11211	11741
1986	8322	8247	10027	12340	18502	16076	15358	15763	14909	14895	10501	8781	12812
1987	8289	8207	9405	11338	10625	10301	11453	13412	17453	15762	9114	9381	11230
1988	8102	8369	9127	10044	6501	8149	7480	11509	13891	14462	9407	8844	9658
Average	9046	8953	10021	12867	15987	14098	11794	13437	16314	16703	12728	11280	12771

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A5

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	9245	8829	9936	11877	10875	10184	9824	9756	12114	12501	8132	11112	10369
1930	8480	8453	9856	10649	7021	9046	7529	11412	13534	13362	9088	8988	9785
1931	8453	8408	9732	10482	6566	7582	7221	9500	14312	12950	9291	8828	9447
1932	8510	8408	9653	9985	10528	9562	10281	13334	14822	17162	13617	9116	11249
1933	9057	8780	10182	14363	19657	16282	10985	11469	14277	19198	18256	9648	13515
1934	10534	11862	14110	19839	22192	18757	18376	20498	20746	14673	9744	14747	16340
1935	8592	8272	9280	11885	18039	14467	10545	9877	14936	16427	13194	9764	12180
1936	8794	8367	10385	11275	13262	10044	9316	11720	17143	15559	8895	11021	11320
1937	8410	8383	9828	11226	10068	9071	7182	9209	12551	12842	8727	9552	9756
1938	8411	8384	9300	10774	16869	13451	11905	13419	18367	15991	11769	9251	12324
1939	8378	8302	10025	10941	11162	9793	9267	13492	16121	14719	8013	9078	10777
1940	8442	8421	10312	11033	10682	10485	11605	13789	13491	14047	8722	10234	10941
1941	8453	8396	9566	11087	10751	9977	9934	11846	12613	11521	7150	8917	10017
1942	8693	8575	9509	14419	17312	13087	9266	11445	12969	14158	10946	7545	11495
1943	8421	8641	9432	11741	18524	14857	10556	18039	16835	17390	13835	8786	13090
1944	8611	8350	9625	11183	10823	9819	9835	10835	12284	9106	7072	11403	9919
1945	8460	8372	9588	11033	8897	8058	7041	7362	12878	13642	10467	8144	9498
1946	8315	8344	9760	11068	17132	14492	12197	14519	18798	17382	12382	9718	12844
1947	8810	8582	10164	17031	19623	17785	13153	12854	16245	17076	11439	10202	13583
1948	8483	13835	12730	14906	19431	17991	11595	13760	19823	22440	13580	9749	14862
1949	10073	9037	10193	12237	14289	13082	12234	14960	17825	16292	10554	14701	12958
1950	8359	8153	9816	13170	19566	17074	14630	13880	17358	20604	17270	9510	14117
1951	9635	11135	13023	18201	19285	18288	16687	15836	21101	17245	14886	13764	15760
1952	9877	12586	11088	14839	18538	15067	10169	15221	19467	16409	11195	12078	13883
1953	8291	8313	9965	11151	17726	15488	11339	10128	14798	17032	14811	9820	12408
1954	8868	8812	10763	14188	19368	18426	12975	13129	18055	20527	16155	10745	14339
1955	15032	10021	12238	14287	17897	13448	9437	10872	12344	16504	18355	15839	13855
1956	8896	10689	12923	17744	19272	18107	13962	18434	21370	21848	14817	13080	15934
1957	9257	9595	9976	14498	18750	13978	12243	11648	19669	19344	10070	13204	13524
1958	8284	8203	9856	10686	18453	15730	10813	12499	18782	16044	9354	9555	12357
1959	8307	8331	11108	15804	19325	18653	15094	14970	15335	20012	16373	9413	14396
1960	14310	15335	14442	16675	19364	15109	12485	15917	14318	16178	14783	13320	15192
1961	8440	8837	11019	12956	19650	18281	15683	13460	16371	20761	12140	10181	13985
1962	8407	8756	9998	12117	17271	13962	9705	14529	15215	15604	11577	10274	12287
1963	8831	9333	11730	15978	17498	16230	10276	12405	14582	14097	11240	9734	12663
1964	8730	8428	9845	12477	19475	13742	10172	10497	12905	20914	16459	9291	12747
1965	10248	10764	11084	17334	19271	18511	12631	16063	18037	17262	13660	13220	14846
1966	9744	9439	10661	13294	18253	12314	9710	14256	14990	14786	12196	13020	12727
1967	8522	8454	9932	13841	19422	18632	13392	10065	14814	21431	15013	10628	13683
1968	9186	9547	10601	13691	19247	16537	12701	11442	14315	15437	13581	13210	13297
1969	12042	11386	12120	15347	19437	17197	13497	17373	19746	17536	12943	10509	14930
1970	8393	8675	9977	12631	17045	14701	9924	10449	13598	14449	12159	10066	11841
1971	8386	8207	9372	12020	19263	18432	12759	16499	20893	21593	15598	9562	14386
1972	9490	8550	10142	13005	19286	18275	17597	19047	20506	22874	17348	14169	15861
1973	10882	8857	9755	14216	12405	10288	10113	10715	12584	13833	8865	15509	11502
1974	8429	8252	9108	11695	20360	18598	17970	20253	20834	22725	19617	8540	15535
1975	10945	8265	9505	12362	18446	14230	11212	10003	16184	18240	17402	14890	13474
1976	9843	10142	12973	18921	19231	18563	14580	15392	19227	17634	16679	11614	15403
1977	16077	8595	9616	11587	10999	9915	10703	11048	12961	9457	6858	15619	11121
1978	8494	8321	9196	10648	12467	10866	12687	14282	15545	15180	13577	8848	11678
1979	10344	8583	10131	11540	10789	11154	11253	11821	14821	15414	8600	9231	11143
1980	8409	8389	9600	10919	15342	12675	9995	12694	18726	15004	9672	9202	11720
1981	8394	8396	9843	16284	19748	18683	12486	11679	15992	16199	14191	8212	13338
1982	9146	8593	10713	14221	19557	18296	15630	14286	16329	21005	16532	11634	14667
1983	11120	9804	10288	14491	19293	16690	15583	14141	15974	14839	15833	13661	14314
1984	9356	8281	13041	14243	18260	15219	14119	13525	12957	17141	15938	12118	13691
1985	9356	8238	10393	12902	14457	10613	9439	13875	16668	14589	8807	10974	11698
1986	8329	8506	10831	13219	18970	16143	15254	15282	14636	15152	9309	8653	12858
1987	8288	8208	10012	12332	10636	10612	11530	13476	16456	15445	9086	8878	11249
1988	8429	8471	9810	10636	6516	8240	7529	11526	13564	13625	9236	8777	9703
Average	9317	9107	10494	13253	16230	14247	11796	13261	16078	16538	12450	10851	12805

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A6a

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8398	8229	9569	12049	11364	10436	10757	12975	12620	13168	9582	15315	11204
1930	8477	8453	9846	10730	7367	9482	8510	13203	15552	15532	9664	9682	10543
1931	8455	8413	9730	11288	7461	8458	8024	12513	15175	14536	9742	9715	10294
1932	8505	8413	9646	10594	10754	9959	13168	15626	17270	19178	15115	9850	12341
1933	9096	9256	10204	14670	19665	17507	12660	13147	16102	21968	20013	11445	14647
1934	11760	12172	13963	19845	24718	18755	18838	24601	22694	16312	10542	15364	17462
1935	8585	8274	9283	12445	18345	14654	11313	11534	17028	18253	15306	9820	12905
1936	9013	8579	9716	11635	13733	10593	10471	14478	20202	17800	10047	11477	12318
1937	8413	8394	9833	11224	11027	9963	7877	11932	14164	14030	9539	10373	10567
1938	8421	8257	9302	11929	17474	14220	13311	15815	21452	18173	13693	10075	13513
1939	8673	8986	9472	11631	12081	9801	10554	15991	18181	16887	9541	10039	11822
1940	8443	8681	9719	11900	10809	11812	12930	16291	15344	16231	9700	11166	11924
1941	8458	8710	9569	11555	11826	11020	11040	13841	14560	12662	8907	9869	11003
1942	8401	8393	9481	16263	18137	13435	9504	13707	15515	15956	12605	8763	12515
1943	8701	8709	9228	13791	19437	16839	12850	21099	19668	20002	15657	10206	14684
1944	8562	8911	9456	12022	11354	10259	10692	13387	13403	11286	8696	13236	10943
1945	8457	8377	9574	11238	9511	9262	7506	8989	14835	15910	12557	9232	10456
1946	8301	8757	9408	12644	18082	15341	14032	17332	21789	19461	14326	10730	14188
1947	9108	9287	10256	18346	19615	18604	16457	15430	19592	18674	13198	11348	14998
1948	9027	14502	12644	15445	19434	18718	15765	16306	23237	25715	14967	10947	16396
1949	11520	9610	10047	12767	15133	14187	14698	17428	21035	18650	11861	15512	14369
1950	8366	8479	9581	14760	19556	18589	17288	16820	19516	23254	18762	10226	15436
1951	9671	11841	13461	19563	19283	19179	18109	21852	23974	19028	16016	15486	17287
1952	9743	13226	10798	15733	19654	16790	11654	18609	23115	18672	12635	14415	15420
1953	8284	8426	9648	11409	19273	17693	12333	12178	17384	20091	16300	11046	13677
1954	8827	9234	10611	14850	19377	18431	17399	15737	20318	22580	17383	12488	15608
1955	15977	10533	12009	14833	18901	13983	9775	12826	14750	18559	19760	16642	14881
1956	9038	11300	12816	19369	19447	18648	18141	21988	25301	24751	16524	14747	17672
1957	9209	10205	9662	15118	19647	15409	14033	14194	23208	21743	11667	15189	14940
1958	8289	8712	9456	12169	19088	17097	12106	15073	22378	18492	9518	10625	13588
1959	8506	9447	11478	16713	19747	18656	18278	18311	17903	22229	17800	10984	15843
1960	14743	15978	14515	17468	19845	16227	14203	18788	16568	18184	15445	14893	16404
1961	9090	9323	11190	13337	19649	18271	18000	16094	18503	23142	13725	11825	15186
1962	8496	9468	9728	12700	17747	14940	10763	17122	17312	17763	13247	11128	13373
1963	8786	9998	12130	16591	18237	17287	11294	14604	16840	16059	12837	11070	13815
1964	9414	8981	9851	13014	19474	15518	11630	12853	14770	24411	17940	10682	14048
1965	10242	11244	10995	19473	19265	18502	18169	20529	21166	20669	14976	15105	16695
1966	9805	10225	10651	14186	19427	12545	10642	16414	16612	17368	13702	15151	13894
1967	8892	8946	9652	14420	19408	18633	15820	11857	17147	24495	16427	114747	14768
1968	9330	10204	10558	14474	19530	18110	14171	12972	16517	17009	14869	15075	14401
1969	11980	12139	12436	15908	19440	18761	17858	20300	22962	19607	14520	13119	16589
1970	8907	9381	9628	13305	18228	15569	11121	12462	16111	17146	13297	11056	13023
1971	8395	8623	9258	14214	19259	18427	18237	20932	24832	25022	17289	11080	16302
1972	10079	9226	9937	13970	19275	18268	24824	21248	23594	26744	18789	15545	17624
1973	11831	9585	9474	15011	13409	10748	11151	13159	14858	15503	9604	16525	12572
1974	8431	8258	9097	13147	22993	20485	20072	23704	23562	26321	21235	9314	17221
1975	11174	8857	9494	13104	19329	16020	13328	12026	18538	21625	19337	16389	14934
1976	10022	10906	12997	19572	20342	18566	18247	20174	23135	19692	18045	13349	17090
1977	16272	9159	9580	12335	11769	10336	10874	12965	14088	13792	5498	17256	11995
1978	8504	8318	9192	10644	14360	12628	14428	17001	18186	17171	14959	8522	12826
1979	10948	8933	9659	12497	10930	12515	12947	14404	16986	16949	10051	10611	12290
1980	8414	8345	9608	11090	16641	14259	10759	14584	21198	17054	10735	10534	12772
1981	8383	8793	9496	18270	19743	18687	16137	13674	18103	18265	15749	10090	14618
1982	8987	9023	10490	14745	19562	18292	18953	19561	19913	24072	18506	14282	16368
1983	11462	10576	10169	15749	19284	18473	18013	18812	19135	17351	17581	15263	15989
1984	9517	9017	13296	15395	19289	17665	17017	16596	16046	20643	17533	13875	15494
1985	9825	8952	10543	14031	15679	11399	10419	16772	18956	17007	10145	12259	13005
1986	8334	9306	10870	13418	19515	18356	17912	19029	16961	17103	11953	9683	14371
1987	8286	9095	10291	13406	10629	11706	12873	15541	17891	16902	9689	10072	12201
1988	8485	8475	9810	11032	8080	8696	8162	13560	14934	15903	9693	9730	10548
Average	9495	9535	10401	14084	16861	15128	13802	16016	18545	18879	13817	12182	14064

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative A6b

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8397	8244	9580	11279	11375	10446	10787	13187	12781	13439	9581	16714	11319
1930	8472	8447	9751	8921	7258	9482	8516	13718	15459	15094	9656	9480	10356
1931	8458	8404	9725	10951	7156	8037	8035	12974	15176	14048	9751	9595	10194
1932	8505	8400	9645	9867	10754	9960	13005	15604	17265	19226	15116	9394	12231
1933	9134	9280	10229	14692	19665	17530	12690	13350	15959	21945	19662	10534	14584
1934	10919	12197	13983	19865	24726	18755	18873	24619	22597	16315	9955	15656	17369
1935	8586	8272	9288	13001	18415	14578	11214	11489	17450	18991	14075	9820	12933
1936	8873	8594	9715	11653	13751	10415	10098	14365	20162	17386	9733	11388	12184
1937	8412	8390	836	11217	11027	9961	8089	12342	14614	13243	9539	10659	10615
1938	8417	8263	9297	11098	17561	14063	13208	15744	21470	18026	13647	9665	13373
1939	8550	8868	9473	11901	12098	9801	10530	16047	17790	16337	9541	9902	11739
1940	8443	8619	9717	11957	10796	11869	13019	16241	15142	16231	9705	11219	11919
1941	8454	8593	9574	11234	11771	11035	11049	14360	15157	12135	7801	9838	10918
1942	8401	8388	9476	16404	18163	13445	9498	13582	15563	15954	12716	8519	12512
1943	8644	8697	9228	13680	19433	16184	12946	21063	19667	19983	15614	9816	14581
1944	8549	8910	9471	12014	11935	10291	10714	13848	13679	11343	7818	12898	10917
1945	8456	8377	9578	11233	9757	9279	7521	8924	14691	15910	12327	9087	10431
1946	8300	8385	9504	12864	18091	15418	14103	17223	21734	19431	14297	10620	14168
1947	9035	9241	10200	18148	19615	18604	16661	15478	19537	18625	13127	11066	14950
1948	8951	14316	12807	15580	19434	18718	15805	16341	23242	25700	14973	10629	16379
1949	10542	9534	10070	12810	15005	14207	14694	17443	21048	18845	11700	15994	14322
1950	8378	8183	9614	14699	19556	18587	17454	16893	19544	23206	18727	9814	15390
1951	9583	11836	13518	19565	19282	19292	18180	21763	23969	18865	16016	15250	17260
1952	9722	13225	11082	15737	19658	16503	11811	18632	23112	18557	12634	14233	15411
1953	8276	8370	9642	11484	19275	17147	12360	12189	17421	20047	16251	10906	13619
1954	8821	9290	10639	14836	19377	18430	17428	15742	20273	22606	17441	12176	15593
1955	15585	10416	12079	14768	18874	14004	9795	12885	14747	18570	19782	16760	14857
1956	8850	11297	12838	19195	19507	18657	18142	21908	25283	24699	16473	14513	17615
1957	9202	10207	9899	15303	19436	15449	14192	14208	23205	21708	11582	14645	14922
1958	8286	8405	9461	12361	19111	17193	12167	14940	22398	18665	9522	10448	13583
1959	8326	9322	11121	16878	19827	18656	18294	18335	17872	22157	17764	10581	15765
1960	14545	15988	14563	17425	19845	16264	14227	18775	16703	18230	15682	14284	16380
1961	8774	9188	10901	13337	19654	18279	18000	16002	18279	23062	13409	11398	15030
1962	8499	9478	9748	12670	17747	14902	10795	17128	17381	17706	13197	11042	13363
1963	8774	10020	12249	16755	18248	17225	11278	14640	16842	16156	12719	10562	13793
1964	9418	8980	9855	13179	19472	15112	11591	12923	14772	24400	17883	10356	13998
1965	10221	11248	11016	19440	19298	18502	18171	20516	21156	20592	15055	14814	16671
1966	9811	10217	10700	14206	19445	12566	10661	16436	16925	17493	13154	14895	13878
1967	8738	8911	9664	14439	19411	18625	15446	12004	17194	24408	16538	11404	14738
1968	9127	10209	10753	14516	19529	17988	14172	13067	16398	17015	15144	14755	14391
1969	12128	12137	12602	15989	19440	18761	17924	20249	22973	19742	14460	11956	16534
1970	8542	9282	9684	13320	18211	15543	11178	12472	16166	17090	13266	10877	12974
1971	8394	8575	9325	14179	19259	18428	18396	20901	24827	24992	17231	10913	16290
1972	10019	9228	10049	13939	19275	18269	24882	21106	23594	26756	18852	15472	17620
1973	11223	9586	9741	15087	13428	10769o	11157	13618	15092	15347	9607	16633	12607
1974	8424	8246	9093	13344	23065	20493	20170	23674	23611	25235	21176	8262	17154
1975	11041	8858	9508	13285	19329	15975	13351	12000	18611	21584	19283	16270	14924
1976	10001	10912	13109	19565	20396	18566	18247	20241	23112	19654	18118	13184	17095
1977	16358	9156	9580	12352	11791	10360	10897	13292	14225	10157	7284	17078	11877
1978	8501	8327	9193	10647	14009	12586	14272	16975	18186	17151	14919	9564	12863
1979	10931	9120	9650	12554	10856	12533	12945	14395	16922	17072	9668	10464	12263
1980	8408	8354	9605	10923	16584	14263	10933	14519	20930	16974	10674	10732	12746
1981	8395	8624	9499	18398	19745	18686	15911	13691	18059	18252	15721	9883	14574
1982	9023	9036	10536	14808	19561	18293	19090	19557	19872	24036	18448	13662	16330
1983	11467	10580	10302	15657	19287	18473	18009	18891	19174	17319	17583	15087	15986
1984	9516	9017	1334	14502	19283	17766	17071	16632	16066	20537	17488	13808	15497
1985	9812	8983	10624	13905	15698	11403	10463	16784	18970	16701	9674	12192	12941
1986	8331	9743	10997	13554	19523	18257	17923	18963	16971	17146	11475	9685	14382
1987	8291	8848	10506	13469	10639	11738	12888	15998	18211	16339	9700	9873	12210
1988	8483	8463	9815	11031	7230	8730	8271	13985	15484	15908	9683	9733	10567
Average	9412	9504	10437	14042	16840	15088	13819	16081	18578	18755	13731	12011	14028

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative B1

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8392	8246	9584	11185	9996	7576	8547	8946	11496	11368	8189	10552	9510
1930	7635	7678	8585	8892	6252	8132	6834	10168	12729	12926	9206	8618	8971
1931	7724	7649	8292	9027	6424	6488	6899	8894	13195	12511	8880	8469	8706
1932	7789	7811	8198	8492	9690	8992	9384	12015	13686	15747	12762	8756	10278
1933	8421	8273	9370	11442	18329	13728	10347	10452	13047	17016	17194	9705	12278
1934	9734	10802	12431	18229	19881	18757	15071	18193	18717	14081	9479	13829	14931
1935	7992	7935	8483	10840	15391	12323	9633	9228	14224	15031	13322	9162	11132
1936	8496	8366	9562	9593	10705	9073	7791	10450	15716	14504	8976	10540	10320
1937	8407	7656	8811	9582	7920	8358	6795	8692	11615	12341	8352	9186	8978
1938	8367	7888	8723	9686	13674	11405	10875	12039	16762	14643	11609	8862	11211
1939	8376	8304	8744	9641	8758	8116	7944	12187	15229	14063	7616	9105	9843
1940	8443	8319	9066	9910	8030	9298	10038	12363	12717	13355	8822	10246	10053
1941	8461	8152	8171	9327	8495	9213	8630	10959	11971	10697	6807	8547	9119
1942	7783	8202	9074	11130	15663	11751	8027	10488	12186	12928	10818	7203	10439
1943	8409	8374	8899	10666	15558	12560	9629	15548	15100	15610	12681	8799	11822
1944	8300	8172	9461	10070	8085	9245	7985	9791	11715	8729	6755	11240	9133
1945	7944	7856	7869	9132	8047	7679	6392	6664	11513	12415	10733	7798	8673
1946	8308	8255	8541	10168	13902	12281	10915	13017	17172	15882	12382	9700	11713
1947	8365	8156	9266	13614	18481	15001	11868	11946	15042	15757	11205	10043	12399
1948	8365	11464	10913	13148	18824	14507	10801	12491	17593	20029	12671	9579	13368
1949	9401	8132	9394	10836	12919	12005	11079	13379	15794	15165	10018	13973	11839
1950	8362	8149	8971	11030	16873	14636	13313	12425	15602	18317	15798	9567	12755
1951	8283	10051	11616	16623	19287	17588	10853	14306	18990	15948	13789	13446	14230
1952	8426	11365	9545	13383	16703	13824	9282	13374	17527	15181	10750	12543	12659
1953	8282	8118	8547	9224	14896	13682	10303	9480	14117	15397	13639	9912	11303
1954	8263	8129	9152	11862	18951	15288	11760	11765	16243	18492	15033	10665	12971
1955	14028	9063	10757	13096	16341	12421	9294	9628	11351	14990	16818	14682	12706
1956	8334	9103	11101	16192	19287	14157	11990	16352	19025	19398	14158	12808	14326
1957	8219	8411	9261	12409	16777	12925	11109	10499	17506	17311	9918	13030	12282
1958	8283	8179	8689	9921	15349	12916	9834	11363	16788	15280	8600	9599	11235
1959	8293	8173	9181	12974	19326	15878	11574	13680	14296	17868	15376	9122	12981
1960	12785	13626	12745	15140	17560	13597	11411	14670	13515	14978	13568	12803	13868
1961	8359	8210	9356	10906	17979	16849	12847	12472	14827	18922	11925	10455	12765
1962	8409	8190	9396	10782	14704	11778	9083	13030	14004	14213	11333	10286	11270
1963	8364	8014	10033	13575	15777	14404	9368	11590	13688	12838	11027	9646	11529
1964	8395	8248	9260	10935	16762	11656	9628	9547	11617	18486	15204	9408	11598
1965	8830	9692	9618	15788	19276	14795	10042	14189	15909	15664	12375	13077	13272
1966	8313	8486	9435	12031	16628	11117	8986	13133	13623	14652	11720	13325	11787
1967	8411	8286	9400	10757	18698	14685	11369	9257	13677	18982	14009	10095	12306
1968	8424	8185	9471	12230	17079	14953	11787	10758	13580	14137	13115	13119	12237
1969	10552	10267	10648	13666	18096	14345	12339	15465	17645	16147	12628	10677	13542
1970	8383	8155	9495	10922	14207	11990	9284	9819	12598	12579	11324	9996	10732
1971	8398	7894	8351	10814	17291	14862	10850	14680	18488	19144	14376	9700	12907
1972	8346	8093	9190	11390	18999	15081	15854	15674	17822	20794	16160	13623	14252
1973	9831	8156	9452	11964	11212	9745	9240	9999	11686	13190	8509	14682	10638
1974	7599	7622	7898	10595	19289	17836	12705	17765	18067	20573	17997	8218	13850
1975	9623	8256	9508	10709	16153	12660	10462	9233	14562	15910	15820	14365	12270
1976	8379	9185	11214	17173	19239	16040	11287	13581	17076	15904	15492	11466	13839
1977	14503	8256	9578	11202	9027	9315	8965	10043	12373	8666	6615	14947	10292
1978	7817	7595	7719	8880	11676	9823	11440	13181	14485	13782	12533	8397	10612
1979	9140	8308	9561	10956	8179	10005	10299	10794	13956	14072	8693	9480	10290
1980	8416	8091	8541	9353	13107	10923	9227	11355	16908	13589	9672	9094	10691
1981	8390	8361	8565	12733	18140	15911	11358	10916	14939	14815	13365	8355	12156
1982	8438	8256	9482	11161	18173	16148	12941	12677	14659	18409	15056	12775	13183
1983	9694	8907	9355	12816	17125	14891	13557	12723	14817	13265	14781	13211	12928
1984	8248	8219	10938	12234	16386	13813	12512	12128	11603	15226	14601	11962	12325
1985	8198	8093	9146	10891	12954	9812	8141	12572	15105	13755	8714	10818	10688
1986	8328	8157	9343	11037	16456	13688	13356	13993	13415	13384	9918	8400	11625
1987	8299	8215	9269	10833	7220	9697	10269	12168	15807	14540	8678	8899	10327
1988	7473	7710	8416	9262	5935	7471	6833	10492	12521	13274	8965	8459	8902
Average	8703	8519	9377	11534	14535	12461	10337	11977	14693	15114	11842	10650	11647

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative B2

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8452	9033	10260	10978	10226	9823	11099	7493	9456	10325	7804	9733.2	9531
1930	6570	7602	9927	9550	10261	9232	9320	8295	10457	11783	8886	8850.1	9204
1931	6552	7412	9073	9684	10245	9088	8575	7371	10773	10825	9018	8884.6	8935
1932	6608	7437	9173	9605	10892	10188	10537	11614	14662	14045	10858	8959.0	10358
1933	7925	8215	10819	13104	19019	15173	9973	10364	12724	17093	17056	8815.5	12500
1934	9885	11810	14247	17934	20724	17957	16963	18092	18455	12168	8852	11246.5	14831
1935	6987	7965	9153	12620	17439	14171	10611	9886	12509	13015	12351	9062.2	11290
1936	8165	7678	10390	10288	12751	10449	9371	11709	16606	9525	7803	9692.4	10343
1937	7194	7569	9980	10175	10575	9613	9163	7134	9304	10819	8372	8849.0	9038
1938	6960	7841	10404	10604	16570	13432	11709	11779	16181	13657	9939	8835.1	11469
1939	7774	7667	9007	10238	12790	10510	9399	10869	13433	10650	8070	8812.4	9912
1940	7396	8019	10376	10892	10140	12796	11082	10935	13176	8964	7906	8854.2	10019
1941	7188	8018	9695	10029	11099	10362	11033	8398	9801	10145	7976	8904.8	9364
1942	6490	7345	8902	13426	16281	13011	9192	10159	10416	11109	10809	8903.7	10480
1943	7207	7493	9639	11669	17099	14845	10564	14730	15406	15139	12709	8846.5	12089
1944	7501	8155	10007	10299	10703	9752	11028	7497	9461	7738	7813	8728.8	9034
1945	6555	7585	8644	9612	1011	8721	7942	7554	10635	11085	8776	8849.5	8816
1946	6920	7598	9962	10446	17185	14241	11253	12728	16614	14421	11436	8860.9	11782
1947	7808	8397	10847	15351	18884	16478	12456	11781	15178	12921	10253	8951.7	12418
1948	7473	13112	12985	13577	18784	16334	10681	11619	17908	20024	12427	8806.2	13621
1949	9409	9172	10640	11171	13417	12942	11754	13378	16448	13472	8399	11403.9	11770
1950	6768	7601	9989	12619	18460	16340	13075	12303	15579	18224	15807	8789.2	12939
1951	9335	11178	13238	16368	18642	17491	14753	13793	18643	15591	12866	9917.9	14292
1952	9287	12525	11400	13558	17831	14582	10052	12941	16858	13727	9716	9903.0	12672
1953	7088	7415	9971	9887	17794	15731	10492	9141	12998	15625	13075	8991.0	11493
1954	7642	8290	11046	12951	18718	17261	11517	11669	16435	18175	15009	8667.9	13092
1955	11982	9888	12398	13168	16864	13284	8577	10410	11057	14858	16620	14364.4	12751
1956	7844	10750	13119	14899	18631	16469	12693	16130	18747	19516	13832	10318.5	14468
1957	8882	9730	10326	13284	17837	13673	11261	10343	16966	17306	8386	9481.8	12264
1958	6885	7512	9619	10669	17323	15129	10177	11452	16693	13196	7714	8812.9	11242
1959	7116	7779	11802	14373	18675	17159	13597	13518	14253	17464	15081	8763.4	13274
1960	13383	14805	14523	14998	18124	15269	12257	13918	12413	14056	12608	10019.1	13838
1961	7778	8121	11338	11902	18999	17468	14339	12010	15306	17924	9212	9531.9	12802
1962	7840	9224	10438	11395	16878	13760	9818	12585	13545	11969	10601	8885.7	11388
1963	7949	8777	12333	14574	16481	16465	10640	10475	11706	10584	10498	8944.0	11595
1964	8134	7801	10069	11538	18570	13656	9308	9475	11935	18192	15357	8931.6	11890
1965	9420	10776	11428	15564	18624	17169	10975	13548	16618	14689	11809	10001.0	13358
1966	8879	9275	10945	12171	17069	13236	10500	11829	12990	10922	11568	10531.1	11632
1967	7743	8357	10411	13108	18765	17831	11777	8857	13699	18679	13947	9295.0	12681
1968	8517	9799	11095	!2637	17943	16099	13029	10363	11435	12915	11927	9855.0	12108
1969	11172	10858	12785	13926	18791	16125	12634	15116	17094	16058	10010	9354.8	13635
1970	7629	8562	10388	11825	16043	13924	10339	9766	11052	12884	8150	8838.2	10760
1971	7007	7791	9921	12065	18609	17358	10800	14093	18684	19067	14387	8857.8	13196
1972	8780	8767	10495	11953	18633	16978	15832	15219	18147	20502	16095	10729.8	14316
1973	9291	9026	10131	13116	10932	11472	11190	7868	9813	12121	8828	12857.8	10520
1974	6520	7259	8515	12497	19160	17744	16149	17536	18132	20356	17985	8887.7	14205
1975	9526	8427	9888	11592	17650	13697	10267	8852	14315	16031	15951	12040.8	12321
1976	8599	10259	13194	16814	18584	17536	13112	13353	16847	16159	15149	8704.5	14003
1977	11987	8739	10030	10539	10847	10211	11318	7778	9986	8038	7919	15031.2	10162
1978	6576	7318	8266	9435	14008	12273	12184	12374	13684	12570	13097	8931.1	10869
1979	8685	7759	10110	10744	12534	11791	9176	8876	15344	9499	8120	8825.8	10098
1980	7210	7865	10080	10315	14875	12981	10177	11635	16850	11395	8056	8895.5	10837
1981	6794	7739	8963	16168	19108	17335	12382	10294	14362	12711	13331	8910.5	12318
1982	8425	8492	10992	13066	18913	17314	12933	12312	15487	17729	15061	10021.7	13369
1983	10059	9897	10624	13332	18240	15852	14242	11903	14718	12163	14290	10371.6	12947
1984	8287	8003	13426	12975	17471	14508	12754	11757	11298	14798	13942	9488.0	12367
1985	7913	7635	10997	11811	13434	11867	9331	11903	14947	9353	8114	8746.8	10481
1986	6419	8508	11651	11866	18832	16018	14457	11862	12420	12126	7888	8854.7	11718
1987	6850	7216	10582	11641	9986	11130	12740	10857	15383	10635	9119	8851.6	10392
1988	6580	7563	8882	9551	10062	9021	8678	9048	9974	10931	8753	8903.7	8972
Average	8062	8706	10658	12285	15902	14038	11387	11342	14100	13794	11289	9549	11734

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative C1

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8393	8316	9581	11175	10876	9373	9014	9370	12044	11861	8413	10856	9943
1930	7962	8059	8995	9296	6562	8553	7189	10674	13281	13450	9456	8550	9361
1931	8057	8045	8689	9447	6739	6794	7246	9394	13775	12988	9119	8709	9085
1932	8121	8204	8583	8876	10168	9409	9999	12701	14394	16322	13246	8998	10753
1933	8424	8270	9368	13285	19302	14370	10893	11002	13646	17873	17873	9664	12854
1934	10133	11266	12994	19093	20885	18762	16983	19112	19590	9721	9721	14300	15621
1935	8333	8267	8908	10829	16451	12966	10126	9710	14821	15639	13797	9556	11619
1936	8504	8364	9716	11090	11199	9503	8231	11056	16488	15115	9249	10963	10796
1937	8409	8398	9226	9993	8273	8732	7144	9142	12166	12844	8598	9450	9367
1938	8426	8259	9300	10341	14318	11986	11491	12710	17612	15355	12045	9118	11747
1939	8383	8295	9481	10527	9155	8475	8402	12819	15885	14650	7838	9379	10276
1940	8440	8320	9715	11030	7994	9714	10988	13048	13401	14050	9089	10443	10523
1941	8458	8336	9236	9784	8901	9656	9109	11539	12532	11235	7025	8791	9550
1942	8152	8203	9479	12182	16446	12357	8489	11112	12820	13532	11213	7430	10952
1943	8417	8365	9237	10673	17067	13803	10234	16542	15860	16325	13301	9089	12412
1944	8298	8180	9460	11025	9324	9675	8399	10306	12230	9168	6966	11631	9560
1945	8301	8261	8255	9566	8448	8072	6747	7058	12173	12962	11116	8031	9085
1946	8309	8249	9331	10707	15168	12415	11568	13877	18034	16588	12829	10001	12259
1947	8371	8158	9268	15374	19392	15744	12491	12607	15338	16214	11641	10351	12932
1948	8371	12455	11616	13902	19435	15737	11364	13190	18560	20962	13163	10038	14068
1949	9806	8534	9391	11534	13535	12743	11855	14137	16689	15780	10644	14444	12422
1950	8373	8141	9441	11028	18368	15864	14073	13170	16362	19297	16470	9620	13352
1951	8549	10603	12135	17389	19282	18287	13581	15117	19961	16444	14286	13893	14959
1952	8796	11982	10137	14003	17529	14539	9827	14265	18472	15646	11152	12953	13276
1953	8285	8253	9644	9839	15611	14368	10851	9878	14594	16041	14298	10247	11829
1954	8250	8297	9616	13504	19367	16714	12353	12477	17045	19378	15569	11033	13638
1955	14592	9485	11223	13673	17094	12993	9436	10263	12127	15556	17515	15200	13264
1956	8300	9875	11850	16968	19283	16594	12740	17204	20106	20431	14680	13245	15109
1957	8213	9154	9255	13432	17577	13584	11776	11161	18482	18207	10242	13449	12879
1958	8291	8170	9464	10696	16122	13674	10399	12048	17723	15669	9257	9865	11783
1959	8290	8177	9935	14042	19314	17465	13007	14394	14840	18901	16020	9442	13654
1960	13331	14371	13327	15839	18356	14252	12026	15458	14168	15641	14036	13215	14503
1961	8365	8214	9640	11922	18893	17820	13523	13087	15699	19674	12293	10821	13335
1962	8403	8192	9378	10968	15806	13428	9431	13781	14753	15216	11736	10513	11804
1963	8373	8020	10744	14761	16542	15222	9859	12199	14384	13364	11414	9907	12068
1964	8389	8239	9253	11043	18192	13292	10021	10048	12263	19487	15788	9691	12144
1965	9183	10204	10148	16576	19266	17421	10688	15014	16758	16271	12876	13495	13992
1966	8560	9040	9726	12689	17480	11649	9316	13819	14476	15387	12107	13759	12334
1967	8420	8285	9393	11578	19415	16610	11889	9764	14369	19984	14535	10555	12903
1968	8424	8858	9657	12964	18022	15690	12372	11284	14198	14656	13549	!3543	12768
1969	10976	10739	11121	14276	19082	15102	13001	16404	18631	16880	13049	11045	14196
1970	8379	8160	9491	11022	15594	13749	9549	10224	13358	13562	11753	10267	11262
1971	8394	8210	9207	10820	18752	15752	11524	15468	19445	20114	14944	10075	13562
1972	8719	8190	9230	12415	19283	16889	17033	16594	18865	21729	16823	14060	14986
1973	10222	8491	9456	12898	11782	9745	9762	10552	12520	13840	8737	15152	11096
1974	7885	8078	8282	10590	19291	18549	16304	18545	19182	21570	18697	8437	14621
1975	9990	8262	9497	10874	17526	13912	11053	9597	15106	16895	16621	14834	12846
1976	8748	9679	12006	18029	19234	17938	12413	14403	18005	16674	16061	11836	14588
1977	15063	8251	9577	11209	10801	9739	9362	10528	12871	9034	6775	15473	10725
1978	8143	7964	8050	9573	12025	10324	12091	13911	14992	14615	12995	8622	11110
1979	9487	8315	9556	10953	9926	10484	10856	11383	14656	14505	9140	9835	10761
1980	8418	8358	8369	9759	13724	11475	9479	12117	17777	14369	9672	9373	11159
1981	8383	8398	9494	13527	19032	16748	11936	11475	15331	15590	13856	8882	12724
1982	8441	8264	9482	12934	19188	17210	13797	13430	15215	19628	15744	13169	13877
1983	10136	9366	9373	13834	18134	15696	14503	13467	15357	14078	15346	13661	13579
1984	8276	8216	11891	13378	17298	14533	13338	12930	12329	15851	15225	12380	12973
1985	8446	8103	9403	12043	13731	10268	9112	13350	15859	14382	9067	11024	11238
1986	8323	8160	9681	11586	17583	15064	14304	14799	14126	14092	10233	8608	12215
1987	8285	8211	9274	10998	9283	9919	10963	12783	16533	15174	8943	9154	10796
1988	7791	8098	8807	9689	6249	7844	7190	10937	13336	13766	9184	8672	9298
Average	8866	8764	9767	12217	15311	13320	11045	12640	15430	15820	12283	10988	12206

Snake River Study - HYSSR Results - System Generation (aMW) - Alternative C2

Wtr Year	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
1929	8650	9446	10700	11471	10726	10313	11689	7959	9671	10690	8300	9789	9968
1930	7071	7954	9901	9981	10770	9537	9798	8776	10951	12143	9096	9077	9587
1931	7051	7912	9291	10162	10743	9587	8732	7874	11282	11221	9253	9109	9351
1932	7099	7906	9224	10104	11202	10860	11091	12144	14839	14580	11237	9179	10788
1933	8239	8496	11272	13676	19515	16537	10835	10806	12665	18008	17705	9045	13066
1934	10300	12319	14887	18720	21830	18458	17461	19425	19360	12593	9236	11196	15485
1935	7219	8190	9582	13172	18215	15359	11172	10298	12424	13587	12751	9216	11765
1936	8475	8049	10747	10753	13333	11504	9933	12231	16822	9974	8297	9785	10827
1937	7411	7941	10181	10598	11049	10056	9628	7636	9760	11239	8613	9068	9431
1938	7198	8047	10786	10922	17320	14548	12382	12318	16430	14346	10283	9065	11970
1939	8045	8079	9409	10702	13185	11008	10474	10898	13990	11097	8296	9040	10351
1940	7617	8414	10712	11312	10652	13412	11698	11499	13826	9380	8415	9073	10500
1941	7414	8176	10084	10517	11627	10879	11630	8862	10291	10634	8485	9126	9810
1942	6999	7750	9051	13912	16821	14221	9759	10609	10301	11656	11142	9125	10944
1943	7499	7884	9939	12113	17927	16109	11256	15370	15801	15865	13260	9067	12674
1944	7782	8359	10443	10778	11187	10230	11593	7970	9897	8194	8308	8953	9474
1945	7046	7969	9148	10112	10498	9215	8459	7905	11178	11708	9058	9074	9280
1946	7155	7897	10110	10728	17322	15411	11938	13324	17113	14758	11811	9089	12221
1947	8128	8713	11302	16091	19474	18060	13215	12334	15413	13538	10584	9058	12992
1948	7751	13455	13557	14210	19821	17780	11623	12274	18457	20952	12895	9033	14272
1949	9827	9631	11094	11670	14048	14143	12493	13990	16945	13930	8616	11362	12314
1950	7012	7994	10142	13172	19293	17592	13825	12921	15758	19205	16467	9016	13532
1951	9771	11683	13821	17118	19136	17992	16310	15347	19218	16311	13294	9897	14990
1952	9553	13080	11884	14184	18690	15803	10669	13688	17240	14403	10033	9984	13270
1953	7371	7754	10410	10346	18541	16994	11084	9578	13011	16424	13589	9094	12016
1954	7912	8665	11395	13460	19218	18124	13043	12382	16701	19050	15535	8897	13698
1955	12489	10359	12931	13745	17634	14452	9052	10824	10954	15573	17274	14343	13304
1956	8151	11114	13685	16662	19132	17443	14464	16624	19742	20519	14317	10385	15190
1957	9281	10189	10775	13906	18669	14889	11966	10913	17385	18181	8652	9436	12854
1958	7148	7906	9903	11164	18030	16398	10791	12019	17192	13732	8230	9039	11795
1959	7308	8177	11975	15032	19175	18058	15100	14076	14333	18342	15659	8991	13852
1960	13765	15497	15181	15689	18946	16457	12929	14523	12377	14735	13024	10097	14437
1961	8059	8511	11800	12313	19506	17977	16344	12573	15454	18838	9469	9606	13372
1962	7900	9606	10879	11875	17623	14967	10380	13161	13574	12593	10938	9096	11882
1963	8246	9116	12851	15245	17254	17765	11229	10924	11645	11156	10840	9042	12109
1964	8419	8187	10477	11913	19313	14891	9832	9951	11894	19194	15923	9078	12422
1965	9662	11293	11906	16334	19117	18200	12963	14216	16938	15536	12253	10069	14043
1966	9293	9726	11451	12735	17849	14407	11081	12315	12931	11382	11909	10478	12132
1967	8018	8635	10846	13667	19266	18333	13760	9330	13806	19720	14457	9380	13268
1968	8729	10251	11574	13218	18779	17349	13680	10754	11327	13495	12297	9926	12617
1969	11602	11361	13331	14545	19285	17770	13767	15875	17558	16792	10300	9331	14293
1970	7896	8724	10818	12340	16844	15157	10943	10188	11015	13623	8412	9060	11251
1971	7286	8023	10344	12536	19117	18132	12874	14779	19327	20069	14933	9087	13875
1972	9046	9185	10929	12506	19136	17970	16666	17028	18832	21661	16739	10776	15044
1973	9703	9461	10549	13697	11446	12030	11770	8313	10209	12591	9051	12776	10970
1974	7018	7757	8668	13028	20169	18244	17054	18716	19223	21335	18723	9118	14921
1975	9932	8827	10281	12100	18444	14897	10873	9315	14477	16949	16599	11942	12891
1976	8693	10728	13747	17643	19086	18262	15005	14065	17225	16968	15719	8930	14672
1977	12508	9008	10451	11020	11329	10688	11860	8208	10402	8358	8419	15016	10607
1978	7078	7824	8764	9529	13817	13357	12757	12927	13808	13312	13546	9154	11322
1979	8971	8141	10314	11154	13130	12367	9671	9379	16101	9951	8372	9053	10550
1980	7434	8069	10399	10740	15568	14124	10772	12137	17267	11987	8382	9120	11333
1981	6973	8144	9278	16709	19598	18384	13879	10721	14392	13358	13773	9131	12861
1982	8618	8918	11475	13671	19407	17997	14962	12946	15751	18803	15713	10088	14031
1983	10408	10378	11073	13957	19152	17174	15191	12617	14936	12877	14824	10436	13589
1984	8549	8401	13994	13597	18398	15787	13587	12426	11395	15719	14510	9573	12996
1985	8265	7790	11466	12395	14114	13036	9924	12519	15096	9809	8347	8980	10978
1986	6926	8397	12157	12404	19377	17636	15447	12472	12449	12912	8369	9071	12301
1987	7018	7714	10830	11883	10486	11676	13390	11386	16093	11081	9330	9076	10830
1988	7079	7979	9379	9918	10561	9521	8831	9565	10495	11419	8977	9120	9403
Average	8384	9085	11059	12814	16506	14992	12243	11936	14419	14467	11713	9687	12276

TECHNICAL EXHIBIT B.

NPPC. 1998. ANALYSIS OF THE BONNEVILLE POWER ADMINISTRATION'S POTENTIAL FUTURE COSTS AND REVENUES

This report by the Northwest Power Planning Council (NPPC) has served as a valuable component of the technical report. Refer to the following website address to download the report.

Website Address = *http://www.nwppc.org/98_11.htm*

TECHNICAL EXHIBIT C.

TRANSMISSION IMPACTS OF BREACHING THE LOWER SNAKE AND JOHN DAY DAM, BPA, JAN 12, 1999

This report was prepared by the Bonneville Power Administration's Transmission Business Line office. The report identifies measures needed to maintain the reliability of the BPA transmission system is the Lower Snake River and John Day Dams are breached. Refer to the following website addresses to download the summary report and technical reports.

Summary Report:
http://www.transmission.bpa.gov/orgs/opi/system_news/lsd_sum.doc

Technical Report:
http://www.transmission.bpa.gov/orgs/opi/system_news/lsd_report.doc

Tables and Nomograms:
http://www.transmission.bpa.gov/orgs/opi/system_news/lsd_tables.xls

System Diagram:
http://www.transmission.bpa.gov/orgs/opi/system_news/500_DIAGRAM_5.doc

GLOSSARY OF TERMS USED IN THIS REPORT:

ADVERSE WATER CONDITIONS. Water conditions limiting the production of hydroelectric power, either because of low water supply or reduced gross head or both. Also sometimes called critical water conditions.

AUTOMATIC GENERATION CONTROL (AGC). Small, but frequent changes in generation necessary to regulate and transmit energy at 60 cycles per second.

AVERAGE MEGAWATT (aMW). The amount of megawatts averaged over a specified time period.

AVERAGE WATER CONDITIONS. Precipitation and runoff conditions which provide water for hydroelectric power development approximating the average amount and distribution available over a long time period, usually the period of record.

BASE CONDITION. The assumed future conditions from which all alternatives are compared against.

BiOp. Biological Opinion.

BPA. Bonneville Power Administration.

BTU. British Thermal Unit.

CAPABILITY. The maximum load which a generator, turbine, transmission circuit, apparatus, station, or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress.

CAPACITY. The load for which a generator, turbine, transformer, transmission circuit, apparatus, station or system is rated. Capacity is also used synonymously with capability. For definitions pertinent to the capacity of a reservoir to store water, see Reservoir Storage Capacity.

Dependable Capacity. The load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. The dependable capacity of a system includes net firm power purchases.

Hydraulic Capacity. The maximum flow which a hydroelectric plant can utilize for energy.

Installed Capacity. The sum of the capacities in a powerplant or power system, as shown by the nameplate ratings of similar kinds of apparatus, such as generating units, turbines, or other equipment.

Overload Capacity. The maximum load that a generating unit or other device can carry for a specified period of time under specified conditions when operating beyond its normal rating but within the limits of the manufacturer's guarantee, or, in the case of expiration of the guarantee, within safe limits as determined by the owner.

Peaking Capacity. The maximum peak load that can be supplied by a generating unit, powerplant, or power system in a stated time period. It may be the maximum instantaneous load or the maximum average load over a designated interval of time. Sometimes called peaking capability.

Sustained Peaking Capacity. Capacity that is supported by a sufficient amount of energy to permit it to be fully usable in meeting system loads.

CAPACITY VALUE. That portion of the at-site or at-market value of electric power which is assigned to capacity.

COMBINED CYCLE PLANT (CC). An electric power plant consisting of a series of combustion turbines with heat extractors on their exhausts.

COMBUSTION TURBINE PLANT (CT). An electric power plant consisting of natural gas or distillate oil-fired jet engines connected to a generator.

CRITICAL PERIOD. The multiple-month period when the limitation of hydroelectric power supply due to the shortage of available water is most critical with respect to system load requirements, as determined from an analysis of the historical streamflow record. The reservoir begins the critical period full; the available storage is fully drafted at one point during the period; and the critical period ends when the storage has completely refilled.

DEMAND. The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, usually expressed in kilowatts or megawatts, for a particular instant or averaged over a designated period of time.

DRAWDOWN. The distance that the water surface elevation of a storage reservoir is lowered from a given or starting elevation as a result of the withdrawal of water to meet some project purpose (*i.e.*, power generation, creating flood control space, irrigation demand, *etc.*).

DRAWDOWN REGIONAL ECONOMIC WORKGROUP (DREW). The interagency group developed to estimate the economic and social effects associated with alternatives being studied in the Lower Snake Juvenile Mitigation Feasibility Study.

DURATION CURVE. A curve of quantities plotted in descending sequential order of magnitude against time intervals for a specified period. The coordinates may be absolute quantities or percentages.

EIA. Energy Information Agency.

EIS. Environmental Impact Statement.

ENERGY. That which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours.

> **Average Annual Energy.** The average amount of energy generated by a hydroelectric project or system over the period of record.
>
> **Firm Energy.** Electric energy which is intended to have assured availability to the customer to meet any or all agreed upon portion of his load requirements.
>
> **Nonfirm Energy.** Electric energy having limited or no assured availability.
>
> **Off-peak Energy.** Electric energy supplied during periods of relatively low system demands.
>
> **On-peak Energy.** Electric energy supplied during periods of relatively high system demands.
>
> **Pumping Energy.** The energy required to pump water from the lower reservoir to the upper reservoir of a pumped-storage project.
>
> **Secondary Energy.** All hydroelectric energy other than primary energy. Secondary energy is generally marketed as non-firm energy.

EXPORTS. Electric power which is transferred from a given power system to another (usually adjacent) power system. Export power must be included in the given power system's loads.

FERC. Federal Energy Regulatory Commission.

FOREBAY. The impoundment immediately above a dam or hydroelectric plant intake structure. The term is applicable to all types of hydroelectric developments (*i.e.*, storage, run-of-river and pumped-storage).

FOSSIL-FUEL PLANT. An electric power plant utilizing fossil fuels (coal, lignite, oil, or natural gas) as its source of energy.

GENERATION. The act or process of producing electric energy from other forms of energy; also, the amount of electric energy so produced.

GENERATING UNIT. A single power-producing unit, comprised of a turbine, generator, and related equipment.

GENERATOR. The electrical equipment in power systems that converts mechanical energy to electrical energy.

GIGAWATT. One million kilowatts.

HEAT RATE. A measure of generating station thermal efficiency, generally expressed as BTUs per net kilowatt-hour. It is computed by dividing the total BTU content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.

IMPORTS. Electric power which is transferred into a power system from another (usually adjacent) power system. Import power is usually considered to be a generating resource.

INFLOW. The rate of water flow into a reservoir or forebay during a specified period.

INTERTIE. An electrical connection between two utility systems permitting the flow of power in either direction at different times between the two systems.

KILOWATT (kW). The electric unit of power, which equals 1,000 watts or 1.341 horsepower.

KILOWATT-HOUR (kWh). The basic unit of electric energy. It equals one kilowatt of power applied for one hour of time.

LOAD. The amount of electric power delivered at a given point.

> **Intermediate Load.** That portion of the load between the base load and the peaking portion of the load.
>
> **Interruptible Load.** Electric power load which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement.
>
> **Peak Load.** The maximum load in a stated period of time. The peaking portion of the load is that portion of the load that occurs for less than eight hours per day.

HEAD LOSS. Reduction in generating head due to friction in the water passage to the turbine: includes trashrack, intake, and penstock friction losses.

HYDROPOWER IMPACT TEAM (HIT). The study team consisting of up to 20 members from Federal and State agencies, Tribes, Northwest Power Planning Council, and several environmental and industry interest groups.

HYDROSIM (or HYDSIM). Hydro Simulator Program. A hydro-regulation model used by BPA.

HYSSR. Hydro System Seasonal Regulation Program. A hydro-regulation model used by the Corps of Engineers.

LINE LOSS. Energy loss and power loss on a transmission or distribution line.

MECHANICAL AVAILABILITY. The ratio of the number of days in total period minus days out of service due to maintenance and forced outages, to the number of days in the total period.

MEGAWATT (MW). 1,000 kilowatts.

NPV. Net Present Value. The adjustment of a stream of investments to a common point in time.

NPPC. Northwest Power Planning Council.

NUCLEAR POWER PLANT. An electric generating station utilizing the energy from a nuclear reactor as the source of power.

O&M. Operation and maintenance.

O&M, R, R. Operation and maintenance, rehabilitation and repair.

OUTAGE. The period during which a generating unit, transmission line, or other facility is out of service.

> **Forced Outage.** The shutting down of a generating unit, transmission line, or other facility for emergency reasons.
>
> **Maintenance Outage.** The removal of a generating unit for required maintenance at any time between scheduled outages.
>
> **Scheduled (Planned) Outage.** The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance in accordance with an advance schedule.

PERIOD OF RECORD. The historical period for which streamflow records exist.

PLANT FACTOR. The ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

PNW. Pacific Northwest.

PONDAGE. Reservoir storage capacity of limited magnitude, that provides only daily or weekly regulation of streamflow.

POWER. The time rate of transferring energy. Electrical power is measured in kilowatts. The term is also used in the electric power industry to mean inclusively both capacity (power) and energy.

> **Continuous Power.** Hydroelectric power available from a plant on a continuous basis under the most adverse hydraulic conditions contemplated. Same as prime power.
>
> **Firm Power.** Power intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.
>
> **Interruptible Power.** Power made available under agreements which permit curtailment or cessation of delivery by the supplier.
>
> **Nonfirm Power.** Power which does not have assured availability to the customer to meet his load requirements.

Prime Power. Same as continuous power.

Seasonal Power. Power generated or made available to customers only during certain seasons of the year.

POWER BENEFITS. The monetary benefits associated with the output of a hydroelectric plant.

POWER PLANT (POWERPLANT). A generating station where prime movers (such as turbines), electric generators, and auxiliary equipment for producing electric energy are located.

PSW. Pacific Southwest.

PUMPED-STORAGE HYDROELECTRIC PLANT. A hydroelectric power plant that generates electric energy for peak load use by utilizing water pumped into a storage reservoir, usually during off-peak periods. The two major types of pumped-storage hydroelectric plants are pump-back and off-stream pumped-storage plants.

PUMP-TURBINE (REVERSIBLE TURBINE). A hydraulic turbine, normally installed in a pumped-storage plant, which can be used alternately as a pump and prime mover (turbine).

RAMP RATE. The maximum allowable rate of change in output from a powerplant. The ramp rate is established to prevent undesirable effects due to rapid changes in loading or (in the case of hydroelectric plants) discharge.

RESERVE. The additional capacity of a power system that is used to cover contingencies, including maintenance, forced outages, and abnormal loads.

Cold Reserve. Thermal generating capacity available for service but not maintained at operating temperature.

Hot Reserve. Thermal generating capacity maintained at a temperature and condition which will permit it to be placed into service promptly.

Spinning Reserve. Generating capacity connected to the bus and ready to take load. It also includes capacity available in generating units which are operating at less than their capability.

Standby Reserve. Reserve capacity which can be placed on-line in a matter of minutes. Includes hot reserve capacity, combustion turbines, and most idle hydroelectric capacity.

System Required Reserve. The system reserve capacity needed as standby to insure an adequate standard of service.

RULE CURVE. A curve or family of curves indicating how a reservoir is to be operated under specific conditions to obtain best or predetermined results. Rule curves can be designated to regulate storage for flood control, hydropower production, and other operating objectives, as well as combinations of objectives.

RUNNER. The rotating part of a turbine.

RUN-OF-RIVER PLANT. A hydroelectric power plant utilizing pondage or the flow of the stream as it occurs.

SBC. Surface Bypass Collector. A type of fish bypass facility.

SPILL. The discharge of water through gates, spillways, or conduits which bypasses the turbines of a hydroelectric plant.

STATION USE. Energy power used in a generating plant as necessary in the production of electricity. It includes energy consumed for plant light, power, and auxiliaries regardless of whether such energy is produced at the plant or comes from another source.

STORAGE PLANT. A hydroelectric plant associated with a reservoir having power storage.

STORAGE PROJECT. A project with a reservoir of sufficient size to permit carryover from the high-flow season to the low-flow season, and thus to develop a firm flow substantially more than the minimum natural flow. A storage project may have its own powerplant or may be used only for increasing generation at some downstream plant.

STREAMFLOW. The rate at which water passes a given point in a stream, usually expressed in cubic feet per second (cfs).

> **Natural Streamflow.** Streamflow at a given point of an uncontrolled stream, or regulated streamflow which has been adjusted to eliminate the effects of reservoir storage or upstream diversions.

> **Regulated Streamflow.** The controlled rate of flow at a given point during a specified period resulting from reservoir operation.

TAILRACE. The channel or canal that carries water away from a dam. Also sometimes called afterbay.

TAILWATER ELEVATION. The elevation of the water surface downstream from a dam or hydroelectric plant.

THERMAL PLANT. An electric power plant which derives its energy from a heat source, such as combustion, geothermal water or steam, or nuclear fission. Includes fossil-fuel and nuclear steam plants and combustion turbine and combined cycle plants.

TRANSMISSION. The transporting or conveying of electric energy in bulk to a convenient point at which it is subdivided for delivery to the distribution system. Also used as a generic term to indicate the conveying of electric energy over any or all of the paths from source to point of use.

TVA. Tennessee Valley Authority.

WATT. The basic electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. One horsepower is equivalent to approximately 746 watts.

WHEELING. The transfer of power and energy from one utility over the transmission system of a second utility for delivery to a third utility, or to a load of the first utility.

WESTERN SYSTEM COORDINATING COUNCIL (WSCC). One of nine regional energy reliability councils that were formed due to a national concern regarding the reliability of interconnected bulk power systems. The WSCC comprises all or part of the 14 Western States and British Columbia, Canada.

[1]Energy Information Administration, 1998. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998.* DOE/EIA-0562 (98), July 1998, pg. 5.
[2]Energy Information Administration, August 1997. *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*. A Preliminary Analysis Through 2015.
[3]Specified power is the power output per unit mass of working fluid.
[4]This is based on the lifetime average, higher heating value.
[5]US Department of Energy, Energy Information Administration, August 1997. *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities.*
[6]US Water Resources Council, Water and Energy Task Force, December 1981. *Evaluating Hydropower Benefits*, pg 3-3.
[7]California Energy Commission, Karen Griffin, Memorandum, 14 April 1998. *Generation Reliability Study for ISO.*
[8]NWPPC, John Fazio, Memorandum to Council Members, 31 Oct 1997. *Value of the Four Lower Snake River Dams to the Power System.*